OAH 16-2500-21807-2
PUC Docket No. G-007, 011/GR-10-977

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATIONS**

This matter came on for public and evidentiary hearings before Administrative Law Judge Manuel J. Cervantes in June and October of 2011.

Public hearings were held in this matter in Rochester and Rosemount on Thursday, June 23, 2011, and in Cloquet on Monday, June 27, 2011.

On October 24-26, 2011, an evidentiary hearing was held in the Large Hearing Room at the offices of the Minnesota Public Utilities Commission (Commission) in St. Paul. The evidentiary hearing concluded on October 26, 2011.

Following the close of the evidentiary hearing, the parties submitted post-hearing submissions and reply briefs. The evidentiary hearing record closed on February 1, 2012.

The following persons noted their appearance:

Michael J. Ahern, Karly Baraga Werner, and Amber S. Lee, Dorsey & Whitney LLP, appeared on behalf of Minnesota Energy Resources Corporation (MERC).

Karen Finstad Hammel, Assistant Attorney General, appeared on behalf of the Minnesota Department of Commerce Division of Energy Resources (Department or DOC).[1]

Ronald M. Giteck, Assistant Attorney General, appeared on behalf of the Minnesota Office of the Attorney General- Antitrust and Utilities Division (OAG).[2]

Andrew P. Moratzka, Mackall, Crounse & Moore, appeared on behalf of the Super Large Gas Intervenors (SLGI).

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[1] Previously named “Office of Energy Security” (OES) and appears as such in portions of the record.
[2] Previously named “Residential and Small Business Utility Division” (RUD) and appears as such in portions of the record.

Elizabeth I. Goodpaster, Attorney at Law, Minnesota Center for Environmental Advocacy, appeared for and on behalf of the Izaak Walton League of America – Midwest Office.

Robert Harding, Shannon McIntyre, Rachel Welch, Sundra Bender, and Stuart Mitchell, Commission Staff were also present.

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STATEMENT OF ISSUES

MERC has requested an annual increase in its natural gas rates of $15,165,305 or approximately 5.18 percent over current rates. Of the total increase, $13,718,788 or approximately 5.89 percent is requested to increase natural gas rates for Peoples Natural Gas (MERC-PNG), and $1,446,517 or approximately 2.42 percent is requested to increase natural gas rates for Northern Minnesota Utilities (MERC-NMU).

On January 28, 2011, the Commission issued a Notice and Order for Hearing directing that an evidentiary record be established on MERC's request. The Commission identified the following issues for parties to address in the course of the contested case proceedings:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?

(2) Is the rate design proposed by the Company reasonable?

(3) Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

(4) Is the Company's proposed revenue decoupling mechanism reasonable?

(5) Is the Company's proposal to consolidate non-gas, margin rates reasonable?

(6) Is the Company's proposal to consolidate gas cost recovery rates reasonable?

(7) Is the Company's proposed uncollectible expense tracking mechanism reasonable?

(8) Over the last five years, what is the percentage increase of employee wages and benefits?

(9) Under Minn. Stat. § 216B.16, subd. 17(c),[3] how should the salary data of MERC's sixth through tenth highest paid officers be treated?

The Commission also allowed parties to "raise and address other issues relevant to the Company's proposed rate increase."

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. BACKGROUND

A. Description of the Company

1. MERC is a Delaware corporation and one of six subsidiary corporations of Integrys Energy Group, Inc. (Integrys). MERC is authorized to do business in Minnesota and its principal office is located in Rosemount, Minnesota.[4]

2. MERC currently serves approximately 209,000 natural gas customers in 51 counties throughout Minnesota. MERC's gas service territories include customers in the southern, east central, and northern portions of the state.[5]

3. MERC has two operating divisions, MERC-PNG and MERC-NMU. These service areas were once owned by separate utility companies until Aquila, Inc. took over their operations in 1985 and 1986. MERC acquired Aquila's natural gas utility operations in 2006 in a sale approved by the Commission.[6] In this proceeding, MERC proposes to consolidate the MERC-PNG and MERC-NMU service areas and rate schedules.[7]

4. MERC's last rate case, Docket No. G-007,011/GR-08-835, was MERC's first rate case following its acquisition of the Minnesota operations of Aquila, Inc. The order approving final rates in that proceeding was issued on June 29, 2009, and amended on September 14, 2009, and December 4, 2009. The Commission authorized rate relief based on a 10.21 percent return on common equity.[8]

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[3] Citations to Minnesota Statutes refer to the 2010 Edition.
[4] Exhibit (Ex.) 19 at 3 (C. Cloninger Direct).
[5] Ex. 19 at 3 and Schedule (CAC-1) (C. Cloninger Direct).
[6] *See In the Matter of the Sale of Aquila, Inc.'s Minnesota Assets to Minnesota Energy Resources Corporation*, Docket No. G-007,011/M-05-1676, Order Approving Sale Subject to Conditions (June 1, 2006).
[7] Ex. 19 at 3-4 (C. Cloninger Direct).
[8] Ex. 19 at 4 (C. Cloninger Direct).

B. Jurisdiction

1. The Commission has general jurisdiction over MERC under Minn. Stat. §§ 216B.01 and 216B.02. The Commission has specific jurisdiction over the rate changes requested by the Company under Minn. Stat. § 216B.16.

2. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 and Minn. Rules 1400.0200, et seq.[9]

C. Application Overview and Procedure

8. In this proceeding, MERC is requesting rate area consolidation, consolidation of its four Purchased Gas Adjustment (PGA) areas into two, and revenue decoupling.[10] MERC also requested an uncollectible expense tracking mechanism, but withdrew that request in subsequent testimony.[11]

9. On November 30, 2010, MERC filed an application seeking an annual rate increase of $15,165,309, or approximately 5.18 percent over current rates. The request for MERC-PNG was $11,783,427 or approximately 5.07 percent, and for MERC-NMU was $3,381,882 or approximately 5.6 percent.[12] MERC's application included proposed interim and final rate schedules, and was based on a 2011 test year.[13] MERC requested interim rates in the amount it applied for as a permanent rate increase.[14]

10. Additionally, MERC seeks a return on common equity of 10.75 percent.[15]

11. On December 1, 2010, the Commission issued a notice to potentially interested parties requesting comments on whether the Commission should accept the filing as substantially complete and whether it should refer the case to the Office of Administrative Hearings (OAH) for contested case proceedings.[16]

12. On December 6, 2010, MERC filed a clarification to the Notice of Change in Rates to separately identify the rate increases requested by MERC if the Commission approved or disapproved its request for rate area consolidation.[17] If rate consolidation is approved, MERC requests a rate increase of $15,165,305 or 5.18 percent ($13,718,788, approximately 5.89 percent, for MERC-PNG and $1,446,517, approximately 2.42 percent, for MERC-NMU). If rate area consolidation is not

[9] Citations to Minnesota Rules refer to the 2011 Edition.
[10] Ex. 1, Notice of Change in Rates, Interim Rate Petition, Summary of Filing (Nov. 30, 2010).
[11] Ex. 43 at 10 (S. DeMerritt Rebuttal).
[12] Ex. 1, Notice of Change in Rates, Interim Rate Petition, Summary of Filing (Nov. 30, 2010).
[13] Exs. 1-5, MERC's rate case filing (November 30, 2010).
[14] Ex. 1, Notice of Change in Rates, Interim Rate Petition, Summary of Filing (Nov. 30, 2010).
[15] *Id*.
[16] Request for Comments on Completeness and Procedural Issues (December 1, 2010).
[17] Ex. 7, Clarification to Notice of Change in Rates (December 6, 2010).

approved, MERC requests a rate increase of $11,783,401, or 5.07 percent for MERC-PNG, and $3,381.870, or 5.06 percent, for MERC-NMU.

13. On December 14, 2010, the Department filed comments, recommending acceptance of the filing as complete and referring the case for contested case proceedings.[18]

14. In its January 28, 2011, Order Setting Interim Rates, the Commission approved MERC's proposed interim rate increase of $7,525,236 ($5,628,322 for MERC-PNG and $1,896,914 for MERC-NMU). The Commission authorized the interim rate increase to take effect on February 1, 2011.[19]

15. The Commission also approved MERC's request to withhold collection of the full amount of the interim rate increase from its Super Large Volume (SLV) customer class. The Commission found that MERC presented "exigent circumstances" under Minn. Stat. § 216B.16, subd. 3, because its SLV customers are sensitive to rate increases, and have the ability to bypass MERC's system, which would potentially result in increased rates for MERC's remaining customers.[20]

16. As part of the interim rate order, the Commission also authorized incorporation of a new base cost of gas set in conjunction with the base cost of gas proceeding in Docket No. G-007,011/MR-10-978.[21] The Commission required updates to the base cost of gas to be filed in that docket and in this rate case docket.[22]

17. In accordance with the Commission's order, MERC is collecting interim rates subject to refund if the rates exceed the final rates determined by the Commission.[23]

18. The initial parties to the proceeding were MERC, the Department, and OAG.

19. The OAG represents the interests of residential and small business ratepayers. Its staff reviews the testimony and schedules filed by the applicant and other parties and files testimony and argument intended to protect those interests.

20. The Department represents the interests of the State's ratepayers in rate proceedings. Department staff reviews the testimony and schedules filed by the applicant and other parties to assure their accuracy and completeness, and files

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[18] Letter from Mark Johnson, Financial Analyst (December 14, 2010).
[19] Order Setting Interim Rates at 3 (January 28, 2011).
[20] Order Setting Interim Rates at 2-3 (January 28, 2011).
[21] *ITMO the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Cost of Gas for Interim Rates in Docket No. G-007,011/GR-10-978*, Order Setting New Base Cost of Gas, Docket No. G-007,011/MR-10-978 (January 28, 2011).
[22] *See* Ex. 13 (1st Update to Commodity Cost of Gas); Ex. 15 (2nd Update to Commodity Cost of Gas).
[23] *See* Order Setting Interim Rates at 2-3 (January 28, 2011).

testimony and argument addressing the reasonableness of the elements of the rate request.

21. On February 9, 2011, the Energy CENTS Coalition (ECC) submitted a Petition to Intervene.[24]

22. On February 14, 2011, the undersigned Administrative Law Judge conducted a prehearing conference at the Public Utilities Commission in St. Paul.[25]

23. At the prehearing conference, MERC indicated that it would file a waiver of the10-month statutory deadline for determining MERC's general rate increase request.[26]

24. By letter dated February 18, 2011, MERC provided a limited waiver of the December 29, 2011, deadline established by the Commission to determine MERC's general rate increase request.[27] MERC's limited waiver required the Commission to issue its final rate order in this proceeding no later than January 30, 2012.[28]

25. On February 18, 2011, the Izaak Walton League – Midwest Office (IWLA) and the Minnesota Center for Environmental Advocacy (MCEA) filed a Joint Petition to Intervene.[29]

26. On February 18, 2011, the Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, LLC, the Minntac and Keewatin Mines of United States Steel Corporation, USG Interiors, Inc., (collectively the SLGI) filed a Petition to Intervene.[30]

27. By letters dated February 18 and 22, 2011, MERC indicated that it did not object to the intervention of IWLA, MCEA, SLGI and ECC as parties in this matter, and the Administrative Law Judge granted intervention.[31]

28. The Administrative Law Judge issued the First Prehearing Order in this matter on April 4, 2011. As provided in the Order, parties of right and intervenors in this matter include MERC, the Department, OAG, IWLA, MCEA and SLGI, and ECC.[32]

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[24] Petition to Intervene of the Energy CENTS Coalition (February 9, 2011).
[25] *See* First Prehearing Order (April 4, 2011).
[26] *See* First Prehearing Order (April 4, 2011).
[27] Minn. Stat. § 216B.16, subd. 2(e) provides MERC with the statutory right to a final determination by the Commission within 10 months of the initial filing. The Commission extended to December 29, 2010, an extension of the 10-month deadline by 90 days pursuant to Minn. Stat. § 216B.16, subd. 2(f).
[28] Letter re Waiver and Updates to Base Cost of Gas (February 18, 2011).
[29] Petition to Intervene of the Izaak Walton League of America – Midwest Office and Minnesota Center for Environmental Advocacy (February 18, 2011).
[30] SLGI Petition to Intervene (Feb. 18, 2011).
[31] MERC Letters re Interventions (Feb. 18, 2011) (Doc. ID No.-59700-01) and (Feb. 22, 2011); First Prehearing Order at 2, OAH Docket 16-2500-21807-2 (April 4, 2011).
[32] First Prehearing Order (April 4, 2011).

29. Under the terms of the First Prehearing Order, other persons who wished to intervene were required to file petitions for intervention by April 14, 2011. The ALJ also established deadlines for the filing of testimony and scheduled the evidentiary hearing to take place on July 19-22, 2011.[33] This schedule was subsequently amended by the Administrative Law Judge's third prehearing order, which issued on September 8, 2011.[34]

30. The Administrative Law Judge also issued a Protective Order on April 4, 2011, to address the handling of non-public information during the proceedings.[35]

31. The ECC, though a party to the proceedings, did not submit testimony or actively participate in the litigation.

32. MERC filed supplemental direct testimony on March 17, 2011, March 31, 2011, and April 5, 2011.[36]

33. The Department, OAG, IWLA, and MCEA submitted direct testimony on May 3, 2011.[37]

34. MERC, the Department, and OAG filed rebuttal testimony of June 2, 2011.[38] On June 30, 2011, MERC, the Department, OAG, IWLA, and MCEA filed surrebuttal testimony.[39]

35. Public hearings were held in Rochester and Rosemount on June 23, 2011. No members of the public attended the hearings.[40]

36. An additional public hearing was held in Cloquet on June 27, 2011.[41] At the outset of the public hearing, the Administrative Law Judge made introductory remarks, followed by short remarks from Greg Walters, MERC's Regulatory and Legislative Manager, and Mark Johnson, a financial analyst with the Department. Following these remarks, three members of the public spoke. A summary of their comments is included as Attachment A.

37. In addition to the public hearings, the Administrative Law Judge received written comments from 14 ratepayers before the close of the comment period on July 7, 2011. A summary of the written comments is included as Attachment A. There was general opposition to any rate increase, particularly during the current difficult economic

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[33] First Prehearing Order (April 4, 2011).
[34] Third Prehearing Order (September 8, 2011).
[35] *See* Protective Order and Exhibit A Nondisclosure Agreement (April 4, 2011).
[36] Ex. 37 (C. Phillips Supplemental Direct); Exs. 30-33 (N. Cleary Supplemental Direct); Ex. 64 (J. Wilde Supplemental Direct).
[37] Exs. 25, 91, 93, 96, 100, 104, 107, 112, 115, 118, 121, and 126.
[38] Exs. 17, 21, 23, 29, 34, 38, 43, 59, 65, 73, 77, 81, 85, 97, 116, and 126.
[39] Exs. 26, 45, 60, 66, 78, 86, 94, 97, 98, 101, 105, 108, 113, 119, 122, and 128.
[40] *See* Ex. 14 (Compliance Filing, Notice of Public Hearings).
[41] *See* Ex. 14 (Compliance Filing, Notice of Public Hearings).

times when many people are unemployed and many seniors are living on modest fixed incomes. Several commentators also questioned the need to raise gas rates when natural gas prices are at or near record low levels. There were also several suggestions that MERC "tighten its belt" and cut costs instead of raising rates.

38. The evidentiary hearings originally scheduled for July 2011 were cancelled due to the State Government shutdown and rescheduled for October 24-28, 2011.[42]

39. On July 25, 2011, the OAG moved to strike the surrebuttal testimony of MERC witness Seth DeMerritt.[43] On August 8, 2011, MERC and the Department filed memoranda in response to the OAG's motion.[44]

40. On August 16, 2011, the Administrative Law Judge heard argument on OAG's motion to strike. The Administrative Law Judge denied the motion at the hearing and issued a written order on September 8, 2011.[45]

41. MERC submitted sur-surrebuttal testimony on September 7, 2011,[46] and the Department and the OAG submitted additional rebuttal testimony on October 12, 2011.[47]

42. The evidentiary hearing was held on October 24-26, 2011, at the Public Utilities Commission, Large Hearing Room, in St. Paul.

43. Prior to the commencement of hearing, the Department and MERC reached agreement on many of the issues. Other issues were resolved during the course of the evidentiary hearing. Among the accords reached between these parties were:

PART 1 - ISSUES WITH REVENUE REQUIREMENT CALCULATIONS

1. MERC's Errors in Surrebuttal Sales Figures (Issue 4)
2. Capital Structure (Issue 6)
3. Other Employee Benefits (Issue 13)
4. Gas Storage Balance Adjustment (Issue 17)
5. Plant Adjustment and Accumulated Depreciation (Issue 18)
6. Actual Deferred Tax Balances (Issue 20)

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[42] Third Prehearing Order (September 8, 2011). The State of Minnesota shut down state services July 1, 2011 until July 20, 2011.
[43] Notice of Motion and Motion to Strike Surrebuttal Testimony of MERC witness Seth DeMerritt (July 25, 2011).
[44] MERC Reply to OAG's Motion to Strike Testimony (August 8, 2011); Department's Response to Motion to Strike Testimony (August 8, 2011).
[45] Third Prehearing Order at 2 (September 8, 2011).
[46] Exs. 18, 35, 39, 46, 61, 74, 79, 83, and 87.
[47] Exs. 27, 95, 99, 106, 109, 112, 120, and 123.

7. Depreciation Expense (Issue 21)
8. IBS Cost Allocation Adjustment (Issue 23)
9. MERC's Cost Allocations to ServiceChoice (Issue 24)
10. Corporate Aircraft Adjustment (Issue 26)
11. Lobbying Expenses (Issue 27)
12. Interest Synchronization (Issue 28)
13. Asset Retirement Obligation (Issue 30)
14. Gas Affordability Program (GAP) (Issue 33)
15. Health Care Reform Legislation (HCRL) (Issue 34)
16. Marketing Expenses (Issue 35)
17. Economic Development Expenses (Issue 36)
18. Advertising Expenses (Issue 37)

PART 2 – OTHER ISSUES

1. Rate Design (Issue 1)
2. Customer Charge (Issue 2)
3. Distribution Rate Area Consolidation (Issue 4)
4. Legal Cost Savings (Issue 9)
5. Conservation Improvement Program (CIP) (Issue 11)
6. CIP Tracker Reduction from CIP Consolidation (Issue 12)
7. Service and Main Extensions (Issue 13)
8. Winter Construction Charges, Abnormal Construction Charges and Tampering (Issue 14)
9. Farm Tap Inspection Program (Issue 15)
10. Capitalization of Repairs and Overhead (Issue 16)

47. The undersigned finds that these agreed-upon adjustments, tariff revisions, accounting practices and recordkeeping requirements are all reasonable and urges their adoption by the Commission.

II. GENERAL PRINCIPLES

48. A reasonable rate enables a public utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in capital

markets.[48] The rate of return should be sufficient to cover operating expenses – including debt service and dividends on stock – and continued assurance in the utility's ability to maintain credit and attract capital.[49]

49. A just and reasonable return should be similar to returns on investments in other businesses having corresponding risk.[50]

50. The determination of reasonableness involves a balancing of consumer and utility interests. Assuring a fair rate of return must be balanced against the rate-paying public's interest in rates that are just and reasonable. Minnesota law requires that any doubt as to reasonableness of proposed rates must be resolved in favor of the consumer.[51]

51. In carrying out its statutory responsibilities, the Commission has announced the following principles for rate design:

(A) Rates should be designed to provide the Company a reasonable opportunity to recover all prudently incurred costs, including costs of attracting capital. These rates, when matched to test year customer counts and sales projections, should allow the Company a reasonable opportunity to collect its revenue requirement.

(B) Rates should be designed to promote an efficient use of resources. As such, they should reflect the costs that classes of customers impose upon the system.

(C) Rates and conditions of service should provide a reasonable continuity with the past. Rate-design changes should be reasonable and, to the extent possible, gradual to prevent drastic impacts on existing customers.

(D) Rates should be understandable and easy to administer.[52]

52. Setting the rates at or near the embedded cost to serve each customer class serves the public interest in assuring that adequate price signals are sent to customers who receive service.[53]

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48 *See Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).

49 *See Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1994).

50 *Id*. at 603.

51 *See* Minn. Stat. § 216B.03.

52 *See In the Matter of a Petition by Great Plains Natural Gas Company, A Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, Findings of Fact, Conclusions of Law and Recommendation, OAH Docket No. 7-2500-17721 at 14-15 (2006) (MPUC Docket No. G-004/GR-04-1487) (http://www.oah.state.mn.us/aljBase/250017721.rt.rcl.htm).

53 Minn. Stat. § 216B.03; Ex. 90 at 4.

53. MERC bears the burden to prove by a fair preponderance of the evidence that it is just and reasonable that it should recover from ratepayers the costs of its claimed expenses.[54]

III. MERC'S REVENUE REQUIREMENT

54. The revenue requirements portion of a general rate case seeks to determine what additional revenue is required to meet the utility's required operating income, based upon a "test year" of operations. The required operating income is derived from determining the amount of investments in the rate base that have been made by a utility's shareholders, and multiplying the approved rate base times the rate of return that is determined to be appropriate for the company.[55]

55. After determining the required operating income, the company's test year expenses and revenues are evaluated to determine the current operating income for the test year (in this case 2011). The difference between the required operating income and the test year operating income is the income deficiency. The income deficiency is converted into a gross revenue deficiency amount.[56]

56. This section of the Proposed Findings pertains to the issues that were raised by the parties regarding MERC's rate base, test year expenses and revenues, and rate of return (computed from the approved capital structure, cost of debt, and authorized return on equity).

A. Rate of Return

57. Minn. Stat. § 216B.16, subd. 6, requires the Commission to give due consideration to the utility's need for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property, and an opportunity to earn a fair and reasonable return upon the investment in such property. The components of determining a fair and reasonable rate of return for MERC in this rate case include a determination of MERC's capital structure, MERC's cost of debt, and a reasonable return on common equity.

58. The Commission's statutory responsibility is to set rates that are just and reasonable.[57] The determination of reasonableness involves a balancing of consumer and utility interests. A reasonable rate enables a public utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in

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[54] Minn. Stat. § 216B.016 (4).
[55] This is portrayed in the revenue requirements summary exhibits of both MERC and the Department. *See e.g.*, Ex. 46 at 31 and Schedules (SSD-1–SSD-6) (S. DeMerritt Sur-Surrebuttal).
[56] Ex. 46 at 31 and Schedules (SSD-1–SSD-6) (S. DeMerritt Sur-Surrebuttal).
[57] Minn. Stat. § 216B.03 (2010).

capital markets. Allowing a fair and reasonable return upon the utility's investment in property to provide the utility service is a factor in setting just and reasonable rates.[58]

59. A fair rate of return is, by definition, the rate which, when multiplied by the rate base, will give the utility a reasonable return on its total investment.[59] A fair rate of return enables the utility to attract sufficient capital at reasonable terms.[60]

60. The need to assure a fair rate of return must be balanced with the public's interest in paying rates that are just and reasonable. Minnesota law requires that any doubt as to reasonableness must be resolved in favor of the consumer.[61]

61. A regulated utility's return must be reasonably sufficient to assure financial soundness and provide the utility adequate means to raise capital.[62] The investor requirement for a return sufficient to cover operating expenses includes debt service, dividends on stock, and continued assurance in the utility's ability to maintain credit and attract capital.[63] A just and reasonable return should be similar to returns on investments in other businesses having corresponding risk.[64]

62. The *Bluefield* and *Hope* standards imply that the public interest is served when utility rates are set at the lowest level consistent with allowing a regulated firm the opportunity to pay a return sufficient to win over investors in capital markets, where risk is a consideration. No public purpose is served by allowing a return that is higher than reasonably expected to be required by investors. An excessive return is unreasonable because it would confer windfall gains on investors, while imposing unnecessary burdens on ratepayers. Moreover, the Commission's obligation to set a fair return does not extend to guaranteeing that the authorized return will be earned. A utility is granted only the opportunity to earn its allowed return.[65]

1. Capital Structure.

63. A utility's capital structure affects its overall rate of return (ROR). The capital structure is a breakdown of a company's sources and costs of capital. It may include long-term and short-term debt, preferred stock and common equity. These amounts are represented as dollar amounts and as percentages of the total capital. As a whole, these amounts are the capital structure, and yield an overall ROR.

64. The Department agreed with MERC's capital structure proposal as modified by Ms. Gast in her rebuttal testimony, and incorporated it in determining a

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58 Minn. Stat. § 216B.16, subd. 6 (2010).
59 *Id.*; and Ex. 25 at 4 (Griffing Direct).
60 Ex. 25 at 4 (Griffing Direct).
61 Minn. Stat. § 216B.03 (2010).
62 *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).
63 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1994).
64 *Id.* at 603.
65 *See* Ex. 25 at 5 (Griffing Direct).

reasonable ROR as discussed in the next section.[66] Ms. Gast's updated recommendation for MERC's capital structure is:[67]

Capitalization

<u>Component Ratio (%)</u>
Long-Term Debt 44.68%
Short-Term Debt 4.93%
Common Equity 50.48%[68]

65. No other party commented on or proposed an alternative to the capital structure agreed upon by the Department and MERC. MERC's revised proposed capital structure set forth above and included in Ms. Gast's rebuttal testimony schedules is reasonable.

2. Cost of Debt.

66. In its initial filing, MERC explained how it developed its rate for long-term and short-term debt.[69] In sur-surrebuttal testimony, MERC reduced the cost of short-term debt from 1.8252 percent to 0.3301 percent to reflect actual short-term costs from January 2011 through July 2011 and the forecasts for the remainder of 2011.[70]

67. The Department incorporated the updated cost of short-term debt in determining its recommendation for the Company's overall ROR.[71]

68. The OAG requested MERC to update the interest rate on short-term debt to reflect the most recent short-term debt forecast from Moody's. The OAG requested MERC provide the Moody's forecast as an attachment to its Reply Brief, and MERC agreed to that request.[72] MERC has prepared the update to the interest rate on the short-term debt and submitted them as an Attachment to its Initial Post-Hearing Brief and filed concurrently with MERC's proposed findings.

69. MERC's cost of long-term and short-term debt is reasonable and should be approved.

3. Cost of Common Equity.

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[66] Ex. 17 at 3, and (LJG-1) (Gast Rebuttal).
[67] Ex. 17 at (LJG-1) (Gast Rebuttal).
[68] Individual Capital Structure ratios do not sum to 100 percent due to rounding.
[69] Ex. 16 at 5-6 (L. Gast Direct).
[70] Ex. 18 at 3-4 (L. Gast Sur-Surrebuttal).
[71] Ex. 27 at 1-2 (M. Griffing Additional Rebuttal).
[72] Ex. 94 at 7-8 (R. Smith Surrebuttal).

70. As a wholly owned subsidiary of Integrys, MERC has no publicly traded common stock.[73] Although Integrys does trade publicly, MERC's regulated local distribution company (LDC) segment only accounts for approximately 11.4 percent of the parent company's earnings which is too little to use Integrys' earnings as the basis for ROE and ROR analysis for MERC.[74] Instead, various financial models using comparison groups must be used to estimate a reasonable return on common equity.[75]

a. Discounted Cash Flow Analysis and Comparable Groups.

71. Since the return on equity is a market-based concept and the market-based information for Integrys is not suitable for this analysis, it is necessary to establish the ROE by other means. The Commission has historically relied upon the Discounted Cash Flow ("DCF") analysis to derive ROE for rate cases. This is the most widely accepted model and one that the Commission has relied on consistently in establishing the cost of equity in public utility cases before the Commission for well over 20 years, most recently in general rate cases involving Otter Tail Power Company and Interstate Power and Light Company.[76] The DCF model provides a ROE estimate that meets the *Hope* and *Bluefield* criteria for a fair return; it yields returns commensurate with returns being earned on other investments with equivalent risks, a rate of return sufficient to enable the utility to attract capital, and returns sufficient to enable the regulated utility to maintain its credit rating and financial integrity.[77]

72. The DCF method uses the current dividend yield and the expected growth rate of this yield to determine a rate of return sufficient to induce investment, and is derived from a formula for determining the net present value, or price per share, of a share of stock.[78] MERC and the Department each recommended a ROE figure; however, MERC's witness Mr. Paul Moul added a leverage adjustment in his DCF calculations, and did not use the DCF model on its own to calculate ROE. Each party began its analysis with the DCF analysis.

73. Although the Department and MERC each employed the DCF analysis, there were some differences in the groups of companies selected for comparison and other variables, yielding different results.[79]

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[73] Ex. 16 at 3 (Gast Direct).
[74] *See* Ex. 26 at 7.
[75] Ex. 22 at 4 (Moul Direct).
[76] *See In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E017/GR-10-239, Findings of Fact, Conclusions of Law, and Order at 43-44 (April 25, 2011) (adopting ALJ's conclusions on use of DCF model at ¶¶ 384-386 of ALJ Report); and *In the Matter of Interstate Power and Light Co. for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-001/GR-10-276, Findings of Fact, Conclusions of Law, and Order at 7-10 (Aug. 12, 2011).
[77] *Id.* at 58.
[78] Ex. 25 at 7 (Griffing Direct).
[79] *See Id.*at 41 (Griffing Direct); and Ex. 26 at 26-27 (Griffing Surrebuttal).

74. To obtain the underlying figures needed for the DCF analysis, the available information is taken from a group of publicly traded companies. The goal is to include companies that are similar to MERC; *i.e.,* companies that are natural gas LDCs that represent approximately the same investment risk as MERC.[80] This group, called the Comparison Group by the Department and the Gas Group by MERC, provides a reasonable basis to estimate the ROE for a utility that is not publicly traded.

75. The Department's expert, Dr. Marion F. Griffing, applied several screens to choose companies for his Comparison Group. Dr. Griffing wanted a group of natural gas companies that resemble MERC, are publicly traded, and have similar investment risk. Dr. Griffing selected eight natural gas LDCs using the following screening criteria: (1) U.S. firms based in the continental 48 states; (2) have shares publicly traded on a stock exchange; (3) currently pay dividends and have positive growth-rate projections from expert analysts; (4) are not expected to merge into or be acquired by another company, (5) have a Standard & Poors ("S&P") credit rating greater than, BBB-; and (6) derive 60 percent of net income, or another earnings indicator, from regulated natural gas operations.[81]

76. The companies included in the Department and MERC comparison groups are identical, except that MERC includes AGL Resources in its Gas Group and excludes Laclede Group and Southwest Gas from the Gas Group.[82]

77. MERC excludes Southwest Gas because its operating area is in an "arid region of the U.S." and has only a small part of its operations subject to decoupling. However, the Department included Southwest Gas because it met the Department's criteria.[83]

78. MERC excludes Laclede from its proxy group because the utility is not subject to decoupling. The Department views MERC's decision to exclude Laclede as an overly restrictive view of the group selection process. Dr. Griffing used credit ratings, a broad-based measure of company risk, and not individual risk elements as the basis for selection of the Comparison Group. Laclede's ROE results are below average, so to drop the company from the DCF analysis would increase the DCF ROEs.[84]

79. The Department excluded AGL Resources from its Comparison Group because AGL plans to buy Nicor; however, news of this acquisition was not publicly known when Mr. Moul selected his group. The Department did not use any data for AGL Resources, nor did Mr. Moul present individual company ROE results. Consequently, there is no data available to enable an evaluation of how AGL's ROE compares with the Department's DCF results. In addition, the announcement of AGL's plans to buy Nicor may have had a large effect on its relative standing within the Gas

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[80] *Id.* at 9.
[81] Ex. 25 at 10-11 (Griffing Direct).
[82] *Id.* at 42. (Griffing Direct).
[83] *Id.* at 11 (Griffing Direct).
[84] *Id.* at 42-43. (Griffing Direct).

Group because of the possible volatility in its stock price.[85] Therefore, any speculation as to its effect on the DCF ROE at this time has little value.[86]

80. To determine a ROE, both Dr. Griffing and Mr. Moul examined earnings growth rate projections and used inputs from three reporting services: Value Line Investment Survey (Value Line), Yahoo! Finance and Zacks Investment Research (Zacks). They both also used a similar dividend-yield equation and similar sources for dividend inputs within the DCF model.[87] While both Mr. Moul and Dr. Griffing used the DCF model, they differ in their application of the DCF model.

b. Expected Growth Rate.

81. DCF analysis requires a determination of expected growth rates and dividend yields in order to estimate this return. The method uses the current dividend yield and the expected growth rate of this yield to determine a required rate of return on an investment opportunity. Since both Dr. Griffing's dividend yields and projected EPS growth rates reflect the most recently available public information at the time he prepared his direct testimony, his updating of these parameters in his surrebuttal testimony to incorporate more recent information that became available also is consistent with DCF theory.[88]

82. The Department relied on projected growth rates as provided by Zacks Investment Research, the Value Line Investment Survey, and Thomson Financial Network estimates provided on Yahoo! Finance (Yahoo! First Call). To determine the expected growth rates, Dr. Griffing used an average of the five-year projected growth rates in EPS from the three sources.[89]

c. Dividend yield.

83. The next component of calculating the required ROE is determining the expected dividend yield, D_1/P_0, where P_0 is the price of a share of common equity today and D_1 is the dividend in the next period.[90] The use of this dividend yield assumes that dividends are distributed at the end of each period (year).[91] Dr. Griffing assumed that dividend increases will be evenly distributed over time and thus adjusted the annualized dividend yield by one-half year's expected growth rate. The sources for Dr. Grilling's dividend yield analysis are Value Line's reports or Zack's website.[92]

84. Generally, historical prices should be avoided in calculating the denominator of the dividend yield since the current equity price per share incorporates

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85 *See Id.* at 43 (Griffing Direct).
86 *Id.*
87 *Id.* at 45.
88 *Id.* at 25-26 (Griffing Direct) and Ex. 26 at 5-6 (Griffing Surrebuttal).
89 *Id.* at 24 (Griffing Direct).
90 Ex. 25 at 24-25 (Griffing Direct).
91 This version of the DCF is known as the constant-growth DCF model. Ex. 25 at 25 (Griffing Direct).
92 *Id.* at 27-28.

all market information considered relevant by investors.[93] However, share prices can be volatile in the short run. This matter is addressed by using a period of time long enough to smooth for short-term aberrations in the capital market. In updating his DCF analysis, Dr. Griffing used stock prices for the most recent 22-day trading period to calculate the dividend yield.[94]

d. Flotation Adjustment to ROE.

85. When companies issue equity, the price paid by investors for the new shares is higher than the revenues per share received by the company. The difference is "issuance" or "flotation" costs--the fees and expenses the company must pay as part of the issue.[95] The return on equity must be adjusted to recognize this difference, or a company will be denied the reasonable opportunity to earn its required rate of return. The adjustment is appropriate even if no new issues are planned for the test year. The effect of the flotation costs carries forward into subsequent years if this adjustment is not made.[96]

86. MERC witness Mr. Moul calculated an average flotation cost for public utilities similar to MERC of 4.0 percent covering the years 2003-2008.[97] The Department accepted this percentage as the flotation factor.[98] Although MERC's flotation cost factor is not MERC's or even Integrys' actual flotation costs, the Company's estimate is in line with flotation costs used in other recent general rate case dockets.[99]

e. Updated DCF Analysis and Department Recommendation.

87. Based on Dr. Griffing's updated DCF analysis, the Department now recommends a ROE of 9.41 percent for MERC,[100] which is higher than 9.32 percent included in Dr. Griffing's direct testimony on May 23, 2011.[101]

88. Dr. Griffing updated his DCF analysis in surrebuttal testimony, using the same methodology and sources of information he used to calculate the ROE in his direct testimony. Updated dividend yields were calculated using the average of closing prices from the 22 trading days for the period of May 16 — June 15, 2011, which correspond to the dates of the growth-rate estimates and dividend payments used in his analysis.[102] Dr. Griffing obtained updated earnings growth rates from Value Line, Zacks' and Yahoo! First Call.[103] Applying the same DCF method used in direct

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[93] *Id.* at 25.
[94] Ex. 26 at 5 (Griffing Surrebuttal).
[95] *Id.* at 28.
[96] *Id.* at 29.
[97] Ex. 22, App. F at 2; and Sch. 7 (Moul Direct).
[98] Ex. *25* at 29 (Griffing Direct).
[99] *Id.*
[100] Ex. 26 at 20 (Griffing Surrebuttal).
[101] *See* Ex. 25 at 24-26 (Griffing Direct).
[102] *Id.* at 5, *see* (MFG-S-1).
[103] *Id.* at 6, and (MFG-S-5).

testimony, Dr. Griffing calculated a mean ROE of 8.52 percent for the Comparison Group, adjusted for flotation costs. The updated DCF results ranged from a low of 7.40 percent to a high of 9.41 percent.[104]

f. Reasonableness of Department's ROE Recommendations.

89. Dr. Griffing assessed the reasonableness of the ROE obtained using the DCF analysis by using two checks: the Capital Asset Pricing Model (CAPM) and the results of Public Utilities Fortnightly's (PUF) survey of ROE decisions across the United States.[105] Dr. Griffing noted that reliance on either the CAPM or the survey of ROEs would not be reasonable, but that these sources provide a check on the reasonableness of the results of the DCF analysis.[106]

90. In addition to the historical CAPM analysis described above, Dr. Griffing replicated MERC witness Mr. Moul's CAPM analysis using forecast data from Value Line and S&P data for dividend yields and growth rates.[107] Borrowing Mr. Moul's methods including his use of a four-year period for calculating compound growth, but rejecting his adjustments for size and leverage, Dr. Griffing updated MERC's CAPM analysis with more recent Value Line data in both his direct and his surrebuttal testimony.[108] The table below includes the most recently updated results:[109]

Alternate CAPM Results With 4-year (MERC) And 5-year (DOC) appreciation period (DOC)

	MERC	DOC
MERC risk-free rate of 4.75%	9.26%	8.89%
DOC risk-free rate of 3.94%	8.71%	8.35%

91. The alternate CAPM results in the table above all fall within the range of results in Dr. Griffing's DCF analysis of 7.40 percent to 9.41 percent, and support an ROE at the top of that range.

92. As a final check on the reasonableness of his DCF analysis, Dr. Griffing analyzed the awards made by all U.S. public utility commissions as tracked by PUF from its online database.[110] Dr. Griffing has used this source as a check on

[104] *Id.* at 6-7.
[105] Ex. 25 at 30 (Griffing Direct).
[106] *Id.* at 6-7.
[107] *See* Ex. 25 at 33-34 (Griffing Direct).
[108] *See Id.* at 34, and Ex. 25 at 8.
[109] Ex. 26 at 9 (Table 1) (Griffing Surrebuttal).
[110] The availability of online state commission ROE award data from PUF makes the data for this analysis more current than in previous cases when Dr. Griffing relied on data published annually in the PUF November issue.

reasonableness in previous general rate cases.[111] A search of the database for the period September 1, 2009 to April 26, 2011, yielded actual orders, excluding settlements, for a period from October 7, 2009 to June 3, 2010.[112]

93. The cases cited by PUF vary in important details such as test years for which analytical data is developed, comparison companies, and filing dates. Thus, a direct comparison between any of the ROE awards and the DOC's recommendation based on its DCF analysis in this case would be inappropriate. Nonetheless, the awards can serve as a check on the reasonableness of the ROE recommendation.[113]

94. The PUF survey demonstrates that the DCF high end result is well within the range of ROE awards made in other states. The PUF survey revealed that the mean ROE award for the 26 natural gas LDCs is 10.15. The median is 10.21. The low award is 9.19 percent, while the high award is 11.00.[114]

95. Dr. Griffing concluded that CAPM and PUF ROE awards indicate that the high end range of his DCF ROE analysis of 9.41 is a reasonable ROE for MERC.[115]

96. Dr. Griffing made no adjustment to the DOC's ROE recommendation to accommodate MERC's proposed decoupling mechanism. Decoupling, like relative size and market value or book value of common equity, is factored into the risk of companies by S&P in its credit ratings. Therefore, the credit ratings relied upon by Dr. Griffing in selecting the DOC Comparison Group already reflects these risk factors.[116]

97. Calculation of the overall allowable rate of return is derived by multiplying each capital structure component by the cost of that component, then adding the results to arrive at the ROR for that particular utility. Dr. Griffing's recommended 9.41 percent ROE results in an ROR of 7.69 percent as the following table demonstrates:

DOC Cost of Capital Recommendation

Component	Ratio %	Cost Rate	Weighted Average Cost
Long-Term Debt	44.60%	6.55%	2.92%
Short-Term Debt	4.93%	0.33%	0.02%
Common Equity	50.48%	9.41%	4.75%
Total	100%		7.69%

98. Both the CAPM analysis as modified to reflect Mr. Moul's S&P Composite 500 DCF analysis and the analysis of the PUF ROE Survey indicate that the DCF result of 9.41 percent yielded by Dr. Griffing's analysis is a reasonable ROE for MERC. The

[111] *See* e.g., Docket No. G008/GR-08-1075, Docket No. G002/GR-09-1153, and Docket No. E017/GR-10-239; and Ex. 26 at 9 (Griffing Surrebuttal).
[112] Ex. 25 at (MFG-9).
[113] *Id.* at 35.
[114] Ex. 26 at 10 (Griffing Surrebuttal).
[115] *Id.*
[116] *Id.*

CAPM results lie within Dr. Griffing's updated ROE range, and the *PUF* survey demonstrates that the DCF high end of range result is well within the range of ROE awards made in other states.

g. MERC's ROE Recommendation.

99. MERC's witness Mr. Moul developed MERC's recommended ROE of 10.75 percent using a multiple-model approach that utilized the DCF model, CAPM, and Risk Premium (RP) analyses.[117] MERC's analysis, as updated in rebuttal testimony, results in an ROE estimate of 9.99 percent using the DCF model, an estimate of 11.70 percent using risk premium analysis, and 11.71 percent with CAPM analysis.[118] Mr. Moul also used the Comparable Earnings method as a check on the results of his other analyses. As updated in rebuttal testimony, Mr. Moul's comparable earnings analysis estimated a ROE of 14.15 percent.[119] Mr. Moul synthesized the products of his DCF, Risk Premium, and CAPM analyses to arrive at a recommended ROE of 10.75 percent.[120]

100. The Department argued that it is not appropriate to use the CAPM and Risk Premium methods to estimate ROE as they are dependent on analyst judgment and susceptible to analyst manipulation of the inputs. The Department pointed out that the Commission stated in its Order in MERC's last rate case that "[u]sing three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required."[121]

101. The Department and MERC agree on the use of:

- the constant-growth DCF model;
- EPS growth-rate estimates for Zacks earnings per share, Yahoo! Finance, and Value Line as DCF model inputs;
- similar dividend-yield equation and similar sources for dividend inputs within the DCF model; and
- the same source (Value-Line) for the initial beta used in CAPM analyses.[122]

h. Differences in the Parties' Recommendations.

102. Five factors account for the difference between the Department's ROE recommendation and that of the Company: (1) differences in the membership of the DOC Comparison Group and MERC's Gas Group; (2) differences in the application of

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[117] Ex. 22 at 17 (Moul Direct).
[118] Ex. 23 at 4 (Moul Rebuttal).
[119] *Id.* at 3, and (PRM-1), Sch. 1 (Moul Rebuttal).
[120] *Id. at 4.*
[121] *See In the Matter of the Application of Minnesota Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-002, 007/ GR-08-835, Findings of Fact, Conclusions of Law, and Order at 10 (June 29, 2009) ("MERC 2008 Order").
[122] Ex. 25 at 40-41. (Griffing Direct).

the DCF model; (3) differences in the data available to conduct the DCF and CAPM analyses; (4) Mr. Moul's inclusion of a Risk Premium model in his analysis; and (5) Mr. Moul's inclusion of CAPM in his analysis, rather than as a check on the reasonableness of the DCF ROE, and several differences in application of CAPM.[123]

103. Mr. Moul's CAPM analysis differs from the Department's CAPM analysis in that it is not as recent as the Department's analysis, and, thus, uses different inputs; it includes a leveraged beta value; and it includes a size adjustment.[124] Mr. Moul's CAPM analysis resulted in an ROE of 11.71 percent.[125] Department witness Dr. Griffing testified that the CAPM analysis allows subjective selection of input values and should be used only as a check on the reasonableness of the DCF analysis.[126]

104. A key difference in the parties' calculations of ROE is MERC's use of a leverage adjustment in its DCF analysis. Mr. Moul included an upward leverage adjustment of 0.55 percent to the ROE in his DCF analysis.[127]

105. MERC argued that the ROE produced by the DCF model, even though it incorporated market values for common equity, does not reflect the appropriate degree of risk because the DCF values are applied to the book value of equity in ratemaking. MERC further stated that when book value is the basis for calculating capital structure, debt becomes a larger portion of the capital structure, causing the risk for a company to increase. The leverage adjustment raised MERC's estimated ROE and is intended to address this perceived increased risk.[128]

106. The Department argued that MERC's leverage adjustment is not appropriate in a DCF analysis. The Department noted that several companies, including Northern States Power Gas in Docket No. G002/GR-06-1429, have made similar arguments to the Commission that the DCF ROE should be adjusted upward because the DCF result is based on market common-equity prices and is applied to the lower book value of the companies, thus not producing the return on investment that investors expected. The Commission has never accepted such a proposed adjustment.[129]

107. The Commission rejected MERC's similar leverage adjustment in its prior rate case, stating as follows:

> The Commission has explained above why it would be inappropriate to adjust the cost of equity to reflect the presumed effects of the current economic downturn. It would be equally inappropriate to adjust the cost of equity to reflect the fact that utility assets, unlike most unregulated assets, are valued at book value for purposes of determining authorized returns,

[123] *Id.* at 41.
[124] *Id.* at 48 (Griffing Direct).
[125] Ex. 22 at 44-45 (Moul Direct); *see also* Ex. 23 at 4 (Moul Rebuttal).
[126] *Id.*
[127] Ex. 25 at 44 (Griffing Direct).
[128] *Id.*
[129] *Id.* at 45.

> Such an adjustment would have to rest on the erroneous assumption that investors buying utility stocks are ignorant of one of the most basic facts of utility regulation – that book value is the norm for pricing utility assets and that returns will be based on book value. Assuming that investors know this basic fact, which they must, since they keep buying utility stock, the only reasonable assumption is that the market value/book value dichotomy is reflected in the stock price. The stock price, of course, is properly factored into the DCF model, making further adjustment unnecessary.[130]

108. Dr. Griffing testified that both the market-to-book and leverage adjustments depend on the dubious assumption that the investors who set the market values for common equity shares in companies used in DCF analysis somehow willingly pay more than book value for common equity shares. According to this logic, the Commission must assume that investors consistently and repeatedly pay too much for utility common equity shares, and thus find themselves receiving a smaller return or taking on more risk than they expected. Then the Commission must intervene and substitute regulatory judgment for that of the investors in order for the investors to receive the appropriate return.[131]

109. Dr. Griffing testified that investors are more sophisticated than implied by Mr. Moul's leverage adjustment.[132] He stated that when investors pay more than book value for common equity they are able to incorporate that information into their calculations of the return they expect from the shares.

110. Dr. Griffing testified further that investors judge the risk of an LDC by its ability to meet its debt obligations and generate a positive return for holders of common equity. These investor judgments are based on the amount of those debt obligations, not the ratio each type of instrument represents of the company's capital structure. The amount of the obligations to a company's debt holders are fixed by the terms of the instruments and not the market value or book value of the company's common equity the risk investors attach to a company is unaffected by the question of whether its capital structure ratios reflect common equity at book value or at market value. Dr. Griffing notes that the Commission concluded in MERC's last rate case that the leverage adjustment is not justified.[133]

111. Dr. Griffing's updated CAPM analysis reflects more recent data than does MERC's. MERC witness Mr. Moul included the return on 20-year Treasury bonds that the Department used as the risk-free rate in its CAPM analysis. MERC arrived at a risk-

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[130] *See In the Matter of the Application of Minnesota Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-002,007/GR-08-835, Findings of Fact, Conclusions of Law, and Order at 11-12 (June 29, 2009) ("MERC 2008 Order").
[131] *Id.*
[132] *Id.* at 46.
[133] *Id.*

free rate of 4.75 percent, compared with Dr. Griffing's updated risk-free rate of 3.94 percent.[134]

112. To develop the market risk premium, Mr. Moul included a historical market-risk premium and forecast market risk premiums in his analysis.[135] For his forecast market risk premium, Mr. Moul used information about the broad equity market from the April 29, 2011 edition of Value Line.[136] Dr. Griffing's more recent Value Line inputs are updated as of June 10, 2011.[137] Mr. Moul also used a DCF analysis of the expected ROE for the S&P 500 from Yahoo! First Call EPS, which Dr. Griffing also incorporated into his alternate CAPM analyses for the purposes of providing a base for comparison of the parties' calculations.

113. Mr. Moul clarified that the Yahoo! First Call growth rate that he used in his S&P 500 analysis is the same as the Yahoo! Finance growth rate.[138] Mr. Moul's updated value as of April 30, 2011, for this input is 10.29 percent.[139] Dr. Griffing's more recent value for this input is 10.38 percent, updated as of June 15, 2011.[140]

114. Mr. Moul also made a choice in the computation of the growth-rate component of his Value Line analysis that significantly affected the forecast market premium outcome. Specifically, Mr. Moul elected to find the annualized growth rate of the percent appreciation potential for the 1,700 stocks covered by Value Line over four years, rationalizing that this growth rate is the midpoint of the three to five-year period to which the appreciation potential applies.[141] Using the Department's updated appreciation potential of 50 percent, Mr. Moul's computation method produced an annual growth rate of 10.67 percent.

115. Dr. Griffing stated that it is more appropriate to spread the appreciation potential over five years because the EPS estimates used in this analysis are for five years, and consistency requires that this growth rate also reflect five years.[142] When the 50 percent appreciation potential is calculated using five years, the resulting annual growth rate is 8.45 percent. When the five-year value is incorporated into Mr. Moul's analysis, the forecast market premium drops from 7.74 percent to 6.63 percent. The combined historical and forecast market premium also declines, dropping from 6.87 percent to 6.31 percent. Similar results are achieved using the Department's risk-free

[134] *See* Ex. 26 at 7, and (MFG-S-3), Sch. 5.
[135] Both DOC and MERC updated their respective historical market-risk premium from the same source—the 2011 edition of Ibbotson's. The updated value for both parties is 6.0 percent.
[136] *See* Ex. 24 at (PRM-1), Sch. 7, p. 4 of 5 (Moul Rebuttal).
[137] *See, e.g.,* Ex. 26, (MFG-S-5), p. 1 of 35 (Griffing Surrebuttal).
[138] Ex. 23 at 17, (Moul Rebuttal).
[139] *Id.* at (PRM-1), Sch. 7, p. 3 of 5 (Moul Rebuttal).
[140] Ex. 26 at (MFG-S-5), pp. 20-35 (Griffing Surrebuttal).
[141] *See* Ex. 25 at 49-50 (Griffing Direct).
[142] *Id.* at 50.

rate of 3.94 percent.[143] The Department pointed to this as one example that shows how the use of selective, subjective inputs can drastically change the result.[144]

116. The Department testified that MERC's witness made other errors in its CAPM analysis as well. In calculating the CAPM, Dr. Griffing used the Value Line adjusted beta, whereas Mr. Moul used his inflated leveraged beta. As in his DCF analysis, Mr. Moul incorrectly applied a leverage adjustment to the beta he used for his CAPM analysis, arguing that the use of book values rather than market values in the ratemaking process means the risk level incorporated in the analysis is too low and, therefore, requires an upward adjustment to beta to reflect appropriate risk levels.[145]

117. The Department argued that this beta adjustment is no more warranted than was the leverage adjustment in Mr. Moul's DCF process.[146] The Department maintained that investors are aware of the implications of paying more than book value for common equity shares and do not need Commission intervention to correct for their decisions in the market.[147]

118. MERC also proposed a size adjustment of 1.20 percent that the Department believes is not justified. According to Mr. Moul, the LDCs in the MERC Gas Group (by extension, in the DOC Comparison Group) have market capitalizations that make them a small set of companies in the broad market. Hence, Mr. Moul concluded that a size adjustment reflecting the greater risk of small companies is needed to avoid understating the ROE for the MERC Gas Group.[148]

119. The Department asserted that Mr. Moul's analysis does not support a size adjustment.[149] According to the Department, MERC's Gas Group companies may have relatively smaller market capitalizations, but their risk level, like that of all regulated monopolies (including public utilities), is less than that of unregulated companies of similar size, or even that of unregulated companies that are much larger.[150]

120. The Commission rejected MERC's similar argument in its prior rate case, stating "[t]he Commission also rejects the Company's claim that the [Department's] failure to make an adjustment to its CAPM inputs to reflect MERC's relatively small size is a fatal flaw, for the reasons set forth by the [Department]."[151] Similarly, the Commission has recently rejected requests for *ad hoc* size adjustments in Docket No.

[143] Ex. 26 at 8-9; and (MFG-S-3), Sch. 5 (Griffing Surrebuttal).
[144] *See* Department Initial Br. at 32.
[145] *See* Ex. 22 at 42 (Moul Direct).
[146] Department Initial Brief at 31-32.
[147] *Id.*
[148] Ex. 22 at (PRM-1), Sch. 1.
[149] Department Initial Brief at 33-34.
[150] Ex. 25 at 51-52 (Griffing Direct).
[151] *See* MERC 2008 Order at 10, n.10.

G002/GR-09-1153 (Northern States Power Gas) and Docket No. EO17IGR-1O-239 (Otter Tail Power Company).[152]

121. The Department's argument regarding this issue is the same in this case; *i.e.*, size is one of several factors that S&P considers in its assignment of credit ratings to companies. Therefore, when Dr. Griffing used S&P credit ratings as a screen in selecting the DOC's Comparison Group, size was taken into account implicitly because the experts at S&P weighed size along with other factors in determining the risk of a company.[153] The Department asserts that MERC's size adjustment should again be rejected by the Commission.[154]

122. The parties' CAPM results are far apart. The Department argued that MERC's inclusion of a risk premium and a CAPM analysis for calculating ROE removes objectivity from the calculation.[155] In contrast to the Department's CAPM analysis (using its market risk premium, unleveraged beta and no size adjustment), which yielded an ROE of 8.35 percent based on forecast/historical computations and the 7.87 percent ROE from the DOC's historical analysis, Mr. Moul's CAPM analysis yielded a ROE of 11.71 percent.[156]

123. The ALJ finds that the wide range in results produced by the CAPM analyses in this case (11.71 percent, 9.26 percent, 8.35 percent, and 7.87 percent to name a few) demonstrates that the CAPM result is highly dependent upon analyst discretion at several points. The ambiguity inherent in the model is why the Department uses CAPM analysis only as a reasonableness check rather than as a part of deriving a ROE.[157]

124. The Commission has historically used the CAPM as a secondary, corroborating resource.[158] Rather than using the CAPM as a check on reasonableness of ROE estimates, MERC presented Mr. Moul's Comparable Earnings approach for this purpose. The Comparable Earnings estimation method is as dependent upon analyst judgment as the risk-premium and CAPM approaches.[159] At most, MERC's Comparable Earnings approach should only be used as a secondary, corroborating resource.

[152] *See In the Matter of the Application of Northern States Power Co., a Minnesota Corporation for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-002/GR-09-1153, Findings of Fact, Conclusions of Law, and Order (Dec. 6, 2010); and *In the Matter of the Application of Otter Tail Power Co. for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E017/GR-10-239, Findings of Fact, Conclusions of Law, and Order (April 25, 2011).
[153] *See* Ex. 25 at 51-52 (Griffing Direct).
[154] Department Initial Brief at 33-34.
[155] *See Id.* at 34-35.
[156] Ex. 23 at 4 (Moul Rebuttal).
[157] *See* Ex. 25 at 52-53 (Griffing Direct).
[158] MERC 2008 Order at 6.
[159] *Id.*

125. As in the CAPM analysis, the analyst's selection of input values significantly affects the outcome of Risk Premium analysis.[160] Furthermore, the focus of the Risk Premium analysis tends to be historical rather than forward-looking. When historical data for bond yields and return on equity are used to determine the risk premium component, the result reflects the average differential between bonds and equity over the time span selected for analysis; however, this differential is not static. The spread between bonds and common equity that investors find acceptable at any given time can depart significantly from the historical value.[161] Consequently, historical results may not provide a reasonable view of the ROE currently necessary for a LDC like MERC to attract investment into the future. The Commission has historically discounted the Risk Premium model due to a history of producing volatile and unreliable outcomes.[162]

126. Both the Risk Premium and CAPM models use inputs that are subject to analyst judgment at every step.[163]

i. The ALJ's Recommendation.

127. The ALJ finds that the DCF model remains the most appropriate method of estimating the forward-looking ROE for a utility because it minimizes analyst discretion in influencing the results of the computation of the ROE. The model uses three inputs: dividends, market equity prices, and growth rates. The first two inputs are determined by the companies and investors making decisions to buy and sell, respectively, common equity shares. Both inputs are market based. The third input, growth rates, as has been noted, is taken from independent experts.

128. The ALJ further finds that the DCF model minimizes the opportunity for analyst influence over the outcome, and, thus, is far superior to the multiple-model approach proposed by MERC. The Commission should reject MERC's multi-model analysis in favor of adopting the Department's recommended ROE of 9.41 percent derived from objective, publicly available inputs.

B. Sales Forecast

129. Verifying the reasonableness of a utility's sales forecast is a critical part of a general rate proceeding since sales forecasts affect revenues, costs and the calculation of the actual rates themselves.[164]

130. MERC forecasted sales and fixed charge counts in the spring of 2010 using actual data through January 2010, and revenues were calculated based on this sales forecast.[165]

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[160] Ex. 25 at 47 (Griffing Direct).
[161] *Id.*
[162] *Id.*
[163] *Id.* at 53.
[164] Ex. 121 at 2 (Heinen Direct).
[165] Ex. 41 at 10 (S. DeMerritt Direct).

131. The OAG and the Department expressed concerns with the data MERC used in its forecast, and its method of calculating customer counts. In response, in surrebuttal testimony, MERC provided actual meter counts for the most recent twelve-month period (June 2010 through May 2011), and corresponding non-weatherized normalized sales. MERC used this data as the basis for a revised sales forecast in this proceeding.[166]

132. In sur-surrebuttal testimony, MERC filed revised schedules that reflect MERC's revenue requirement position based on its revised 2011 test year sales forecast (Revised Forecast).[167]

133. The Department accepted MERC's Revised Forecast, included in Mr. DeMerritt's surrebuttal testimony, with the condition that MERC conduct an audit of its billing systems. Mr. Heinen testified that, based on his review of MERC's Revised Forecast, he was generally confident that the information is consistent, produces sales and customer counts that create reasonable results to set final rates, and would create test year rates that do not harm ratepayers.[168]

134. MERC has agreed to conduct a complete audit of its billing system, as proposed by the Department and the OAG. MERC, the Department, and the OAG have agreed that the parties will reach mutual agreement on the use of an external auditor and the scope of the audit on MERC's billing systems. MERC has agreed that if the audit identifies any understatement of the sales and customer counts, the record should be reopened to make any necessary modifications to the final rates in this proceeding.[169]

135. If significant issues with MERC's data are uncovered during the audit that would result in lower rates for MERC' s ratepayers, the Department recommends that the Commission reserve the right to revisit the rates set in this proceeding.[170]

136. MERC's Revised Forecast reports total sales 23 percent lower than the total sales reported in MERC's original sales forecast.[171]

137. After accounting for the changes in commodity costs and the Conservation Cost Revenue Charge (CCRC), MERC's revised sales forecast and customer counts would result in a net decrease in revenue of approximately $1,893,486 over MERC's originally filed revenue figure and total sales 23 percent lower than total sales reported in MERC's initial sales forecast.[172]

138. The OAG raised concerns about the discrepancy between MERC's initial and revised sales forecasts and questioned the reliability of the data. Ultimately,

[166] Ex. 45 at 4-5 and Schedule (SSD-2) (S. DeMerritt Surrebuttal).
[167] Ex. 46 at Schedules (SSD-1-SSD-6) (S. DeMerritt Sur-Surrebuttal).
[168] Ex. 123 at 13 (A. Heinen Additional Rebuttal).
[169] Hearing Transcript, Vol. 1 at 104-105 (S. DeMerritt); Vol. 3 at 6-7.
[170] Ex. 123 at 17-18 (A. Heinen Additional Rebuttal).
[171] Ex. 46 at 12 (S. DeMerritt Sur-Surrebuttal).
[172] Ex. 46 at 12 (S. DeMerritt Sur-Surrebuttal).

despite its initial opposition, the OAG concluded that MERC's initial sales forecast should be adopted in this proceeding.

139. MERC and the Department also indicated in their post-hearing briefs that MERC's initially filed sales forecast is acceptable for use in this ratemaking proceeding.

140. Since MERC has agreed to the proposed billing audit, including the rate revision provision, the data issues identified by the Department and the OAG have been addressed.

141. The Administrative Law Judge concludes that MERC's initial sales forecast is reasonable and recommends that the Commission use MERC's initial sales forecast for setting rates in this proceeding, noting that it will result in a revenue requirement nearly $1.9 million lower than MERC's revised sales forecast.

C. Pension Expense

1. MERC Employee Pension Expense.

142. MERC proposed a test year pension expense amount of $1,863,823 for MERC employees, along with approximately $529,830 for MERC's share of pension expense for IBS employees.[173]

143. According to MERC, its pension expense is determined using an actuarial analysis performed in accordance with SFAS No. 87, and Generally Accepted Accounting Principles (GAAP).[174] MERC's actuary, Towers Watson, performed the analysis in 2010 based upon a December 31, 2009, measurement date.

144. As shown in Table 4 below, MERC's pension expense has increased every year since 2007:

MERC's Administrative and General Pension Expense[175]

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Forecasted	2010/2011 $Increase
Pension Expense % increase	$561,054	$628,385 12%	$975,056 55%	$1,433,896 47%	$1,863,823 30%	$429,927

145. The Commission's ratemaking function of establishing a reasonable level of pension expense in rates differs from the utility's accounting or bookkeeping function. The purpose of a rate case is to set the level of pension expense to be recovered in rates until the next rate case. This purpose is different than the function of financial accounting, where pension expense changes annually. Further, it is not uncommon that

173 Ex. 107 at 9-10 (Johnson Direct).
174 Ex. 36 at 7 (Phillips Direct).
175 Ex. 107 at 11, Table 1 (Johnson Direct).

an expense calculated according to GAAP for financial statement purposes is different than the amount allowed for ratemaking purposes.[176]

146. Some of the assumptions used to calculate MERC's pension expense include the expected return on plan assets, anticipated salary increases, and discount rates. According to MERC, the assumptions are ultimately determined by MERC with the concurrence of its actuary, and reviewed for reasonableness by MERC's external auditor on an annual basis.[177] The assumptions used in calculating MERC's pension expense, and corresponding values for 2007 through the test year, are shown in the table below:

Assumptions Used to Determine MERC's Pension Expense[178]

Assumption:	2007 Jan-July	2007 July-Dec	2008	2009	2010	2007-2010 Average[179]	2011 Test Year
Discount Rate	5.87%	6.40%	6.40%	6.45%	6.15%	6.25%	5.90%
Expected Return on Plan	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.25%

Assets							
Rate of Compensation Income:							
Non-Bargaining	5.50%	5.50%	4.50%	4.50%	4.50%	4.90%	4.50%
Bargaining	5.50%	5.50%	4.00%	4.00%	4.00%	4.60%	4.00%

147. In pension accounting, the discount rate and expected return on plan assets are inversely related to pension expense. In other words, all other things being equal, if either the discount rate or the expected return on plan assets decreases, the annual pension expense increases. By contrast, the rate of compensation increase is directly related to pension expense; therefore, any increase in the rate of compensation increases the annual pension expense.

148. In pension accounting, where assets are invested over a long span of time, seemingly small changes in assumptions about these factors can significantly affect current pension expense, even though a utility's employees would not receive any more pension benefits in the future.[180]

149. Several assumptions used to calculate MERC's pension expense are not reasonable. First, MERC's pension expense was calculated during the first half of 2010 using a December 31, 2009 measurement date. Since MERC's initial analysis was performed, however, the financial markets have recovered significantly. For example, in 2009, the average closing price for the Dow Jones Industrial Average was approximately 8,885.7 compared with a closing price in 2010 of 10,668.6, an increase of over 20 percent. The financial market recovery continued in 2011. For the period

[176] Tr., Vol. 2 at 157 (Johnson Testimony).
[177] *Id.* at 12-13.
[178] *Id.*, Table 2, DOC Ex. 107 at 12, and MAJ-7 (Johnson direct).
[179] Calculated by the DOC.
[180] Ex. 107 at 14.

through April 1, 2011, the Dow Jones Industrial Average was up an additional 12.76 percent over the average closing price at year-end 2010.[181]

150. In addition, MERC's initial test year discount rate was 5.90 percent, 35 basis points lower than the average of 6.25 percent for the period 2007-2010.[182]

151. Moreover, MERC's test year expected return on plan assets is 25 basis points lower than the 2007-2010 average return of 8.50 percent.[183] All of these assumptions increase pension expense in the test year, without increasing pension payouts to future retirees.

152. In addition, MERC's test year annual rate of compensation increase of 4.5 percent for non-bargaining employees and 4.0 percent for bargaining employees appears too high. In contrast, in determining its labor expenses as part of the non-fuel O&M expenses, MERC assumed wage growth of only 3.0 percent for 2010 and 2011.[184]

153. MERC has failed to demonstrate the reasonableness of its proposed pension expense; the Company's pension expense is overstated. The significant recovery in the financial markets since 2009 and the unreasonable assumptions used to calculate pension expense mean that the amount of pension expense that MERC proposes to charge to its customers is unreasonably high.

154. MERC's rebuttal testimony adopted one of the Department's recommended changes, to base the calculation on information from December 31, 2010, rather than December 31, 2009. This change decreased MERC's proposed pension expense significantly, resulting in a decrease of $66,595 even though MERC also decreased its discount rate.

MERC's Administrative and General Pension Expense[185]

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Initial Forecast	2011 Updated Forecast
Pension Expense % increase over prior year	$561,054	$628,385 12%	$975,056 55%	$1,433,896 47%	$1,863,823 30%	$1,797,228 25%

[181] *Id.* at 15.
[182] Ex. 108 at 16 (Johnson Surrebuttal).
[183] *Id.*
[184] *Id.* at 15; and MERC Ex. 41 at 12-13 (DeMerritt Direct).
[185] Ex. 108 at 14, Table 1 (Johnson Surrebuttal).

MERC's Rebuttal Assumptions Used to Determine MERC's Pension Expense[186]

Assumption:	2007 Jan-July	2007 July-Dec	2008	2009	2010	2007-2010 Average[187]	2011 Initial	2011 Updated
Discount Rate	5.87%	6.40%	6.40%	6.45%	6.15%	6.25%	5.90%	5.80%
Expected Return on Plan Assets	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.25%	8.25%
Rate of Compensation Increase								
Non-Bargaining	5.50%	5.50%	4.50%	4.50%	4.50%	4.90%	4.50%	4.50%
Bargaining	5.50%	5.50%	4.00%	4.00%	4.00%	4.60%	4.00%	4.00%

155. MERC's updated discount rate of 5.80 percent is the lowest rate in recent history, 10 basis points lower than its initially proposed 5.90 percent, and 45 basis points lower than the 2007-2010 average of 6.25 percent.[188] The ALJ does not find it reasonable to set pension expense recovery using such a historically low discount rate.

156. Integrys completed an asset/liability study during 2010 to determine the appropriate pension fund asset allocation, and as a result of the study, changed the pension fund investment mix. Based on the study, Integrys, an independent investment consultant, MERC's independent actuary, and MERC's independent auditor agreed on an expected return on assets assumption of 8.25 percent.[189]

157. MERC's investment mix may have changed from 2010 to 2011 along with the Company's proposed expected return on assets, and it could change again. While MERC's proposed expected return on plan assets of 8.25 percent may be appropriate for financial statement purposes, it is not appropriate for ratemaking purposes. As with the discount rate, the assumptions used to determine pension expense are determined annually, and fluctuations in a company's corresponding pension expense, due to these and other changes, are likewise reflected annually in the Company's financial statements. Like the discount rate, the amount of pension expense established and recovered in a rate case will remain constant in rates until the Company's next rate case. Thus, it is critical that the level of pension expenses built into rates be reasonable going forward until MERC's next rate case.[190]

158. MERC clarified that the higher wage increases assumed for the pension expense calculation included both wage increases and promotions. However, MERC failed to demonstrate that a 4.0 percent wage increase assumption for bargaining employees and 4.5 percent increase for non-bargaining employees is reasonable for setting rates. Many ratepayers submitted written comments indicating they will be getting no increase in their income, or in some cases, decreases in their income, yet the Company proposes that ratepayers bear 100 percent of MERC's pension costs, and fund MERC's assumptions of a 4.0 to 4.5 percent increase in wages every year for

[186] Ex. 107 at MAJ-7 (Johnson Direct); and Ex. 108 at 14, Table 2 (Johnson Surrebuttal).
[187] Calculated by the Department.
[188] Ex. 108 at 16.
[189] Ex. 38 at 5-6 (Phillips Rebuttal).
[190] Ex. 108 at 18 (Johnson Surrebuttal).

calculating pension costs. In addition, MERC fails to acknowledge that as employees at higher pay grades retire, they are replaced by employees at lower pay grades, which should result in reducing the wage increase assumptions used by the Company.[191]

159. The ALJ finds that MERC has failed to demonstrate by preponderance of the evidence that its test year pension expense calculation is reasonable and in the public interest.

160. The ALJ further finds that the pension expense calculation as recommended by the Department is reasonable. MERC's pension expense calculation should have included the following: the discount rate should be set at 6.25 percent (the average of 2007-2010 levels), the expected return on plan assets should be set at 8.50 percent (also the average 2007-2010 level), the assumed wage increases should be set at 3.0 percent (consistent with the Company's proposed wage increase for 2010 and 2011). However, the Company did not provide a revised test year pension expense calculation based on the assumptions recommended by the Department in direct testimony, but instead, provided a revised pension expense calculation with the same expected return on plan assets, wage growth rates, and an even lower discount rate. Thus, the ALJ finds that the Company's test year pension expense should be set no higher than 2010 actual levels. This reduces MERC's initial test year employee pension expense by $429,927.[192]

161. While it is not necessary to make a specific adjustment at this time for the fact that MERC does not require any pension contribution from its employees and is, thus, asking ratepayers to fund 100 percent of MERC's pension obligation, the ALJ accepts the Department's recommendation that the Commission require MERC to fully support in its next rate case the reasonableness of having ratepayers pay 100 percent of MERC's pension obligation.[193]

2. MERC's Share of IBS Employee Pension Expenses.

162. In surrebuttal testimony, Johnson noted that the methodology and assumptions used to calculate the IBS employee pension expense are the same as those used to determine the MERC employee pension expense.[194] As a result, the Department raised the same concerns about the IBS employee pension expense as it raised for MERC's pension expense calculations regarding several of the Company's unrealistic assumptions used to calculate the expense, including no contribution by employees, unreasonably low discount rate and expected return on plan assets, and 4.0 to 4.5 percent wage increases every year.[195] Consequently, the Department recommended the same treatment for IBS employee pension expense as it did for

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[191] Ex. 108 at 18-19 (Johnson Surrebuttal).
[192] *Id.* at (MAJ-S-3) (Johnson Surrebuttal); and Ex. 109 at 9 (Johnson Additional Rebuttal).
[193] Ex. 107 at 16 (Johnson Direct)
[194] *Id.* at 25 (Johnson Surrebuttal).
[195] *Id.* at 25-26.

MERC employee pension expense, that MERC's share of IBS employee pension expense be set at 2010 actual levels.[196]

163. For the same reasons identified above with respect to the MERC employee pension expense, the ALJ finds that MERC's share of the IBS employee pension expense should also be set no higher than actual 2010 levels. This decision reduces MERC's test year share of the IBS employee pension and other actuarial determined benefits by $35,890.[197]

164. The Department and the OAG recommended the removal of Account 926210 from MERC's 2011 revenue requirement. MERC agreed to this adjustment and also to the removal of this non-qualified pension plan costs in Account 926019, which contains MERC's allocation of IBS costs.[198]

D. Refund of Annual Employee Incentive Costs

165. MERC and the Department agree that MERC should refund to customers any underpayment of incentive pay costs included in MERC's 2011 test year revenue requirement.[199]

166. MERC witness Ms. Cleary proposed the refund be provided via an incentive compensation tracker, whereby any cumulative net under-payments of incentive compensation, on a combined basis, will be amortized and refunded to MERC's customers in future general rate case proceedings. Ms. Cleary explained that generally it is understood that expenses may vary in the period between rate cases. The standard practice with expenses included in a test year is to adjust them in the next rate review. As such, there is likely to be some variation in the amount of incentive compensation that is paid each year. For that reason, the incentive tracker accurately reflects the utility ratemaking process and efficiently accounts for the inherent fluctuation of incentive compensation payments.[200]

167. Ms. St. Pierre expressed concern that the incentive tracker as proposed by Ms. Cleary may lessen the refund to customers because it might combine executive compensation that is not included in the test year revenue for MERC's ultimate recovery, and because MERC proposes to amortize any refunds in the tracker until the next rate case.[201]

168. MERC witness Ms. Cleary clarified that the proposed tracker would record only the difference between the amounts of approved rate-payer recovered executive and non-executive compensation, and does not include executive incentive pay that is not approved.[202] Mr. DeMerritt testified that the incentive tracker would include

[196] Ex. 109 at 16 (Johnson Additional Rebuttal).
[197] *Id.* at (MAJ-AR-2), 1, 12, col E.
[198] Ex. 39 at 2 (C. Phillips Sur-Surrebuttal).
[199] Ex. 34 at 6 (N. Cleary Rebuttal); Ex. 112 at 29 (M. St. Pierre Direct).
[200] Ex. 34 at 6-7 (N. Cleary Rebuttal).
[201] Ex. 113 at 23 (M. St. Pierre Surrebuttal).
[202] Ex. 35 at 3 (Cleary Sur-Surrebuttal).

compound interest carrying-costs at MERC's prevailing short-term debt rate approved in this docket.[203]

169. Over the course of the proceeding, the Department and MERC reached agreement on the amount of incentive compensation (nonexecutive and executive) to be included in the test year.[204] However, the parties did not agree on the appropriate mechanism for returning unpaid incentive compensation to ratepayers in the future. The Department recommends that the Commission establish a refund mechanism that returns unpaid incentive compensation to ratepayers rather than providing a windfall to shareholders.

170. Annual executive incentive compensation is based on meeting certain financial and customer performance goals.[205] When incentive compensation is built into base rates, ratepayers pay towards incentive compensation even if performance goals are not met, and no such compensation is paid. MERC does not have a refund mechanism in place if Integrys does not pay the incentive amounts embedded in base rates.[206] The Department argued that any such compensation embedded in base rates and not paid to employees is an unreasonable benefit to the Company's shareholders at the expense of its ratepayers.[207]

171. Incentive Compensation is paid out after Integrys' audited financial results for the incentive year are available, but no later than March 15 of the year following the incentive year.[208]

172. The Department recommends that MERC be required to:

- Refund any incentive compensation costs included in the test year revenue requirement that are not paid out in a particular year;
- Make an annual compliance filing within 60 days after the incentive compensation awards are or would have been paid;
- Include in the compliance filing sufficient information to determine whether a refund is required and, if so, the amount of the refund; and
- Use a per dekatherm refund mechanism with any such refund.[209]

173. While MERC did not oppose the requirement to file annual reports within 60 days after the incentive compensation awards are paid, it did oppose requiring a refund when incentive compensation is not paid to employees.[210]

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[203] Hearing Transcript. Vol. 1 at 120 (S. DeMerritt).
[204] Tr. Vol. 1 at 79 (Cleary Testimony).
[205] Ex. 112 at 28 (St. Pierre Direct).
[206] *Id.* at 29 (St. Pierre Direct).
[207] Department Initial Brief at 46.
[208] Ex. 30 at (NEC-1) p. 4 (Cleary Supplemental Direct).
[209] Ex. 114 at 10-11 (St. Pierre Additional Rebuttal).

174. The Commission's ratemaking practice has been to allow recovery of incentive compensation, but to recognize that incentives, by their nature, may not be paid out to employees. The Commission has typically required utilities to refund unpaid incentive compensation to customers.[211] Requiring the utility to refund unpaid incentive compensation amounts to customers is an alternative to disallowing incentive payments altogether. In addition, refunding unpaid compensation amounts also responds to public comments questioning why ratepayers should pay an incentive as well as a salary to a utility employee to do their job, particularly during a time of high unemployment.

175. MERC has not demonstrated by a preponderance of the evidence that it's proposed "incentive tracker" is reasonable, nor has the Company explained why MERC should be treated differently from other utilities in Minnesota on this issue.[212] The ALJ finds that MERC's proposed tracker is unreasonable, and that the Department's refund proposal should be adopted.

E. Rate-Payer Supplied Funds

176. In direct testimony, the OAG recommended a rate base adjustment for ratepayer supplied funds. The OAG reasoned that MERC funds its obligations for pensions and post-employment benefits at a different level than the expense level included for recovery in rates. The OAG maintained that the cumulative difference between funding and expense from 2007 through the projected 2011 test year is $74,159, and that MERC's rate base for pensions and post-employment benefits should be reduced by that amount.[213]

177. MERC agreed to adjust the rate base for ratepayer supplied funds, but in the amount of $71,159. OAG witness John Lindell calculated the adjustment as the difference between the accumulated expense and funding for years 2007 through the 2011 test year. Specifically, he calculated a reduction of $130,627 related to pensions and an addition of $56,468 related to post-retirement benefits. The calculation for the reduction related to expenses, however, is $127,627, which is the difference between $3,096,734 (2007-2011 total pension funding) and $2,969,107 (2007-2011 total pension funding). MERC therefore calculated the net reduction to rate base to be $71,159 (-$127,627 + $56,468) and accordingly reduced the revenue requirement by that amount.[214]

178. The OAG continues to maintain that the rate base should be reduced by $74,159 in recognition of ratepayer supplied funds in excess of what MERC has funded for employee benefit obligations.[215]

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[210] Ex. 113 at 20-21 (St. Pierre Surrebuttal).
[211] *See e.g., In the Matter of the Application of Northern States Power Company for Authority to Increase it Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-91-1, Findings of Fact, Conclusions of Law and Order (November 27, 1991).
[212] Ex. 113 at 23 (St. Pierre Surrebuttal).
[213] Ex. 100 at 20-22 and Schedule (JJL-7) (J. Lindell Direct).
[214] Ex. 39 at 3 (C. Phillips Sur-Surrebuttal).
[215] Ex. 101 at 19 (J. Lindell Surrebuttal).

179. The evidence demonstrates that MERC reduced the rate base by $71,159, and that amount accurately reflects the difference between funding and expenses for its employee benefit obligations. No further adjustment is necessary.

F. Test Year Non-Fuel O&M Expense Methodology

180. MERC's actual 2010 non-fuel O&M expenses were not available when MERC filed its initial application in this proceeding. MERC initially calculated its 2011 test year non-fuel O&M expenses by first applying 2010 inflation rates and 2010 known and measurable adjustments to MERC's 2009 actuals to determine projected 2010 non-fuel O&M expenses, and then applying 2011 inflation rates and 2011 known and measurable adjustments to the 2010 forecasted number.[216]

181. The Department recommended MERC adjust its test year calculations. Mr. Johnson recommended that MERC calculate its 2011 test year non-fuel O&M expenses by using 2010 actual non-fuel O&M expenses adjusted for inflation for 2011 and known and measurable changes. Mr. Johnson explained that, in general, the most recent actual expenses should be used whenever available.[217]

182. MERC agreed to this change in methodology, which resulted in a decrease in test year non-fuel O&M expenses of $2,215,136.[218]

183. OAG witness Mr. Lindell recommended that MERC's revised test year non-fuel O&M expense be reduced by an additional six percent because MERC's initial 2010 forecasted expenses that were based on its 2009 actuals had resulted in a six percent over-estimate of MERC's 2010 actual expenses.[219]

184. The OAG's additional adjustment, however, is not necessary because the methodology that MERC used to determine its test year non-fuel O&M expense no longer contains the component that Mr. Lindell's adjustment seeks to correct. MERC witness Mr. DeMerritt explained that the correction was already made by Mr. Johnson, accepted by MERC, and reflected in MERC's revised test year non-fuel O&M expenses submitted in its rebuttal testimony and sur-surrebuttal testimony.[220]

185. Exhibit 47 in the record demonstrates that applying the OAG's additional adjustment to MERC's revised test year non-fuel O&M expenses would result in an overall reduction to MERC's initially filed test year non-fuel O&M expenses by 9.5 percent, and ignores the rather low bad debt expense incurred by MERC in 2010 as discussed later. Exhibit 47 also demonstrates that MERC's revised test year non-fuel

[216] Ex. 43 at 6 (S. DeMerritt Rebuttal).
[217] Ex. 107 at 6-7 (M. Johnson Direct).
[218] *See e.g.*, Ex. 43 at 6 (S. DeMerritt Rebuttal); Ex. 107 at 5 (M. Johnson Direct); *see also* Ex. 112 at 41-42 (M. St. Pierre Direct).
[219] Ex. 102 at 5 (J. Lindell Additional Rebuttal).
[220] Hearing Transcript Vol. 1 at 101 (S. DeMerritt).

O&M expenses based on MERC's 2010 actual expenses already reflects the OAG's 6 percent recommended reduction.[221]

186. Because the record reflects that the OAG's recommended correction to MERC's initially filed test year non-fuel O&M expenses has already been made, and that an additional reduction to MERC's revised test year non-fuel O&M expenses would not accurately reflect MERC's test year costs, the ALJ finds that the OAG's recommended additional six percent reduction is not necessary.

G. Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFDUC)

187. CWIP is the balance shown in a utility's rate base for construction work not yet completed, but in progress. MERC did not include any amount for CWIP in its initial filing. In rebuttal testimony, MERC requested that 2011 CWIP be adjusted upward by $914,193 based on the use of actual 2010 13-month averages as opposed to forecasted data.[222]

188. The Department agreed with MERC's calculation and initially recommended that the Commission increase the test year rate base by $914,193 for CWIP.

189. The Company has not historically calculated AFUDC in the absence of a specific project, and AFUDC was not calculated on the CWIP balance proposed in MERC's rebuttal testimony because the balance does not represent specific projects that would be subject to an AFUDC calculation. Instead, MERC's 2010 CWIP balance represents an annual average balance of CWIP.

190. In his additional rebuttal testimony, OAG witness Mr. Lindell argued that standard regulatory practice requires the inclusion of an AFUDC, an income statement account, as an offset to CWIP.[223] At the hearing, the Department witness Mr. Johnson supported the OAG's contention that AFUDC needs to be reflected on the income statement as an offset to CWIP when he testified that:

> There is a tie between CWIP and AFUDC. AFUDC is Allowance for Funds Used During Construction. And what AFUDC represents are the costs of these funds that are being used during the construction phase of the capital project before it is completed and put into service and then, henceforth, depreciated. Some people commonly refer to these costs as interest expense costs. Generally under accounting and ratemaking, these — these costs are capitalized and included in the CWIP balance with the offsetting entry going to the income statement.[224]

191. The Department supports the OAG's position that AFUDC needs to be reflected on the income statement as an offset to CWIP in the rate base. Moreover, the

[221] Ex. 47 (O&M Cost Reduction Comparison).
[222] Ex. 43 at 11 (S. DeMerritt Rebuttal).
[223] Ex. 102 at 10-12 (Lindell Additional Rebuttal).
[224] Tr. Vol. 2 at 151 (Johnson testimony).

Department recommends that the Commission reject the inclusion of CWIP if AFUDC is not included in the income statement.[225]

192. The ALJ finds that it is not appropriate to increase CWIP by $914,193 unless a reasonable offset for AFUDC in included in the income statement. If the Commission approves the CWIP adjustment, MERC should propose an AFUDC amount in its compliance filing. If MERC is unwilling or unable to do this, the Commission should reject the requested increase to CWIP.

H. Additional Property Tax Expense

193. MERC filed the instant general rate proceeding with an estimate property tax expense of $4,617,000 for the 2011 test year. In supplemental direct testimony, MERC requested an increase in its 2011 property tax obligation above the amount included in the 2011 revenue requirement. In December 2010, MERC received final Assessment Notices indicating that its 2010 property tax obligation would actually be $5,618,227, or $1,001,227 higher than estimated. The assessed valuation of MERC's property in Minnesota increased from $118,759,000 in 2009 to approximately $150,660,600 in 2010. MERC has protested the assessments.[226]

194. Based on the 2010 actuals, MERC estimated its 2011 property tax obligation to be $5,733,578 (inclusive of $375,000 of property tax on storage gas and 2.2 percent inflation) or $1,116,578 more than the amount included in the 2011 revenue requirement as initially filed. MERC, therefore, in its supplemental direct testimony requested an increase of $1,116,578 for its property tax obligation above the amount included in the 2011 revenue requirement.[227]

195. The Department recommended that the Commission allow MERC to increase Taxes Other Than Income by $1,116,578 related to property tax expense contingent on updates to MERC's property tax assessment protest. The Department also requested that administrative notice be taken of any decisions on property taxes made before the Commission's final order.[228]

196. MERC stated in rebuttal and surrebuttal testimony and at the evidentiary hearing that there were no significant events or changes in the status of the tax assessment protest. MERC witness John Wilde stated that the Company and the Minnesota Department of Revenue were having discussions, but that the Company had no estimate of the time required to resolve its appeal of the 2010 tax assessments.[229]

197. In rebuttal testimony, the OAG recommended an increase in MERC's property tax adjustment of $462,000 instead of the $1,116,578 increase MERC

[225] DOC Initial Brief at 48.
[226] Ex. 64 at 2-3 (J. Wilde Supplemental Direct); Ex. 71 (Notice of Appeal, Utility Property Tax for the 2010 Assessment).
[227] Ex. 64 at 1-3 (J. Wilde Supplemental Direct).
[228] Ex. 112 at 10-14 (M. St. Pierre Direct).
[229] Ex. 65 at 3 (J. Wilde Rebuttal); Ex. 66 at 2 (J. Wilde Surrebuttal); Hearing Transcript Vol. 1 at 139-153 (J. Wilde).

proposed.[230] Mr. Lindell claimed that assessed property values should not be expected to maintain the high levels they reached in 2010 for property taxes. With his additional rebuttal testimony, he attached pages of tax information for property that MERC owns in Washington County, Minnesota. Based on those schedules, he claimed that property tax valuations fluctuate from year to year and that MERC's property will decline in value from $1,096,900 in 2010 to $890,400 in 2011, and that the 2011 property valuation will be used to determine the property taxes payable in 2012. He argued that MERC should not be allowed to include the high valuation and taxes for 2011 when it can be shown that valuations and the resulting taxes can be expected to decline in 2012.[231] Mr. Lindell recommended that MERC's proposed increase be limited to $462,000, a ten percent increase over 2010 in property taxes.[232]

198. At the evidentiary hearing, MERC witness John Wilde introduced the actual tax assessments issued by the Minnesota Department of Revenue in August 2011, which show that MERC should expect an increase in assessed value from $1,096,000 in 2010 to $1,140,941 in 2011, or a 4.1 percent increase.[233]

199. MERC's Minnesota personal property value assessments for all counties was $112,625,033 in 2009, increasing to $144,618,203, or 27.8 percent in 2010, and increasing to $155,921,183 or 7.8 percent in 2011.[234]

200. For all three years, even though the assessed values for certain counties may have decreased, there is a pattern of increased value assessments. With an actual 7.8 percent increase in the assessed value of its centrally assessed Minnesota property for 2011, MERC would need to experience a 5.6 percent reduction in the actual tax rate levied on 2011 assessed values compared to the tax rate levied on 2010 assessed values to achieve the inflationary adjustment of 2.2 percent used to update MERC's 2011 property tax obligation.[235]

201. At the time MERC made its initial filing in this matter, even though it knew the 2010 assessed value of its property, it did not know the actual tax rate that would be assessed by the applicable local taxing jurisdiction. Until MERC learned the actual tax rate that would be assessed in December 2010 it could not determine the impact the 2010 assessed values would have on 2010 actual property tax obligations.[236]

202. The record evidence shows that, based on the actual assessed value of MERC's property it is likely that MERC will actually experience an increase in Minnesota property tax obligations greater than the $1,116,578 requested in the supplemental direct testimony.

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[230] Ex. 102 at 12-14 (J. Lindell Rebuttal).
[231] Ex. 102 at 12-13 (J. Lindell Rebuttal).
[232] Ex. 102 at 14 and Schedule (JJL-6) (J. Lindell Rebuttal).
[233] Ex. 67 (Department of Revenue, 2011 Assessed Value, New Scandia Township).
[234] Ex. 68 (Department of Revenue, 2009 Assessed Value, Company Total); Ex. 69 (Department of Revenue, 2010 Assessed Value, Company Total); Ex. 70 (Department of Revenue, 2011 Assessed Value, Company Total).
[235] Hearing Transcript Vol. 1 at 143 (J. Wilde).
[236] Hearing Transcript Vol. 1 at 144 (J. Wilde).

203. The 2011 revenue requirement should be increased by $1,116,578 to account for MERC's increased property tax obligation.

204. In addition, the Commission should take administrative notice of any decisions on MERC's property tax appeals made before the final order in this proceeding.

I. Rate Case Expense

205. MERC forecasts total rate case expenses of $1,268,000 and proposes to amortize 87.7 percent, or $1,112,036, over a three-year period. The 87.7 percent reflects the removal of rate case expenses for MERC's non-utility business "Service Choice." This amortization results in test year expenses of $370,679. The types of expenses included are costs for MERC's capital expert, legal fees, and charges from Vertex for changes to the billing system, state agency and Office of Administrative Hearings charges, newspaper notices, and travel expenses.[237]

206. Rate case expenses were increased by $26,998 annually due to an increase in newspaper notice fees as explained by Mr. DeMerritt in rebuttal testimony.[238] The Department agreed to this adjustment.[239]

207. A three-year amortization is appropriate because the Commission approved a three-year amortization period for the rate case expenses in MERC's last rate case and MERC anticipates filing its next rate case within the next three years.[240]

J. Work Asset Management (WAM) and PeopleSoft Upgrade Expenses

208. MERC included in its rate base the carrying costs and depreciation expense charges from IBS for the implementation of WAM and the upgrade of the PeopleSoft accounting and supply chain system. MERC witness Ms. Kupsh testified that the 2010 software "upgrades" for the PeopleSoft systems were not typical "upgrades", but instead, more akin to a new implementation. PeopleSoft Version 8.0 was four generations behind PeopleSoft Version 9.0. PeopleSoft Version 9.0 included the addition of the following new and substantial modules: (1) E-Procurement; (2) Strategic Sourcing; (3) Expenses; (4) E-Settlement; (5) E-Supplier; and (6) The User Productivity Tool.[241]

209. WAM is a set of computer system applications that manage the lifecycle of utility assets, as well as the activities to construct, maintain and regulate these assets. The benefits of the WAM upgrade include: (1) a controlled material selection process that promotes standardized designs; (2) the consistent application of extension rules through default settings; (3) the consistent and correct application of accounting; (4) the

[237] Ex. 41 at 26 and Schedule (SSD-15) (S. DeMerritt Direct).
[238] Ex. 43 at 15 and Schedule (SSD-3) (S. DeMerritt Rebuttal).
[239] Ex. 113 at 24-25 (St. Pierre Surrebuttal).
[240] Ex. 41 at 26-27 (S. DeMerritt Direct).
[241] Ex 29 at 3-4 (T. Kupsh Rebuttal).

tracking of work streams and identification of bottle necks; and (5) improved communication by allowing customers access to job information.[242]

210. The OAG recommended that MERC's 2010 expense level for software be used for its 2011 test year. OAG witness Mr. Lindell argued that the 2010 expense incorporated the software upgrades and using that amount for 2011 was reasonable. [243]

211. The record evidence does not support that MERC's 2010 expenses for software accurately reflects the costs that MERC will incur in the test year for PeopleSoft and WAM upgrade expenses. Ms. Kupsh explained that in 2010 only 7 months of amortization expense and return on investment were recorded for the upgrade to PeopleSoft Version 9.0, which was only $993,329. The 2011 test year includes a full year of these costs which is $1,357,410. She also explained that the WAM upgrade costs are allocated from IBS based on meter counts, and that MERC accounts for 6 percent of the meters. Therefore, it is appropriate for IBS to allocate 6 percent of the WAM upgrade costs to MERC, which is the amount that MERC has proposed in its test year.[244]

212. The ALJ recommends that MERC's test year include $1,357,410 to account for the costs that MERC will incur from the PeopleSoft and WAM upgrades.

K. Regulatory Assets and Liabilities

213. FERC Account 182.3 allows for regulatory assets. It states, in part, that:

> A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies.

214. MERC proposed to include $9,364,574, representing MERC's net regulatory assets in the rate base. In Docket No. G007,011/M-06-1287, the Commission approved $8,934,972 in amortization for future recovery related to MERC's purchase of Aquila.[245]

215. The OAG recommended the removal of the remaining regulatory assets that were not approved in Docket No. G007,011/M-06-1287. OAG witness Mr. Lindell testified that because MERC did not obtain prior Commission approval, it has not met the requirements for recording them as regulatory assets to be included in the rate base.[246]

216. MERC has agreed to reduce the rate base for two regulatory asset items totaling $392,860 as recommended by the OAG,[247] but disagrees with removing the

[242] Ex 29 at 4-5 (T. Kupsh Rebuttal).
[243] Ex. 100 at 14 (J. Lindell Direct).
[244] Ex 29 at 4-5 (T. Kupsh Rebuttal).
[245] Ex. 100 at Schedule JJL-5 (J. Lindell Direct).
[246] Ex. 100 at 17-20 (J. Lindell Direct).
[247] Ex. 46 at 22-24 (S. DeMerritt Sur-Surrebuttal).

Cloquet plant amortization as a regulatory asset. Mr. DeMerritt testified that the Cloquet Plant amortization was included in MERC's rate base when Integrys acquired the Minnesota natural gas operations of Aquila in 2006. In addition, the Cloquet plant amortization, labor actuals, and labor loader were included in rate base in MERC's last rate case, Docket No. G007,011/GR-08-835.[248]

217. Mr. Lindell argued that a Commission-approved rate base that may have included an item for setting rates in an earlier case does not establish a precedent for obtaining recovery or a return in a subsequent case.[249] Mr. Lindell testified that it was the OAG's position that a utility should not record a regulatory asset without specific Commission authorization supporting future cost recovery.[250]

218. FERC Account 182.3 allows for regulatory-created assets that results from the ratemaking actions of regulatory agencies. MERC has demonstrated that its Cloquet plant amortization was approved in its last ratemaking proceeding.

219. The ALJ finds that the rate base should include $43,498 in the rate base that represents the Cloquet plant amortization, labor actuals, and labor loader that were included in the rate base in MERC's last rate case in Docket No. G007, 011/GR-08-835.

L. Test Year Uncollectible Expenses

220. MERC initially forecasted $2,820,465 of uncollectible expenses for the 2011 test year. After applying the Department's recommended non-fuel O&M adjustment to MERC's uncollectible expenses, MERC's revised test year uncollectible expenses were adjusted to $1,134,941.[251]

221. Department witness Mr. Johnson expressed concern with the wide variation that was shown in MERC's actual bad debt expense from 2008 to 2010. He was also concerned with the variation in the change in the test year forecast because $2,820,465 appeared to be too high and $1,134,941 appeared to be too low. Mr. Johnson recommended that MERC's test year uncollectible expense be leveled by setting uncollectible expense at its historical average of 0.776545 percent of test year sales revenues.[252] MERC accepted this recommendation.[253]

222. The OAG also agreed to the leveling technique and to the historical average amount set by MERC and the Department. It does not agree that the revenue deficiency from this rate case be included in the bad debt expense for MERC's test year. OAG witness Mr. Lindell argued that this would create a false sense of accuracy,

[248] Ex. 44 at 19-20 (S. DeMerritt Rebuttal).
[249] Ex. 101 at 14-15 (J. Lindell Surrebuttal).
[250] Ex. 100 at 17 (J. Lindell Direct).
[251] Ex 107 at 23 (M. Johnson Direct).
[252] Ex 107 at 23-24 (M. Johnson Direct).
[253] Ex. 43 at 8 (S. DeMerritt Rebuttal).

and that the level of bad debt expense sometimes fluctuates significantly from year to year.[254]

223. Mr. Lindell's argument does not reflect the record evidence that the most accurate way to reflect the cost that MERC will incur in bad debt expense in the test year is to account for MERC's total test year tariff revenues. MERC explained that its test year revenues will include the revenue deficiency that is decided in this case.[255] Department witness Mr. Johnson agreed that it is appropriate to apply all tariff revenues, including the revenue deficiency in this case, when calculating the Company's test year uncollectible expenses.[256]

224. MERC witness Mr. DeMerritt acknowledged that it is difficult to produce an exact estimate of the final revenue deficiency to incorporate into this calculation. Therefore, he proposed to use the Department's initial revenue deficiency recommendation of $11,907,362, which is lower than MERC's proposed test year revenue deficiency.[257]

225. Mr. Johnson agreed that it is appropriate to use the Department's revenue deficiency of $11,907,362 as a proxy for calculating test year uncollectible expense. He also noted that if there are material changes to that amount the Commission could require MERC to adjust the bad debt expense to reflect the revenue determined by the Commission in this rate case. The Department, therefore, recommends that MERC's test year uncollectible expenses be increased by $896,946.[258]

226. The record demonstrates that incorporating the Department's initial revenue deficiency recommendation of $11,907,362 into the calculations for the test year uncollectible expense represents the most reasonable and accurate cost measurement tool presented.

227. MERC has agreed to the exclusion in the rate base of approximately $244,000 of GAP start-up costs and $148,555 for the deferred debt-LT arrearage regulatory asset.

M. Uncontested Adjustments

228. MERC filed testimony as part of its application on a number of uncontested financial matters involving various adjustments to the test year. The findings above describe the areas where parties who audited MERC's filing had issues with the treatment of certain amounts and expenses in MERC's filing. No party filed testimony challenging any other aspects of MERC's financial filings. As a result, the uncontested portions of MERC's filing should be approved.

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[254] Ex. 101 at 6 (J. Lindell Surrebuttal).
[255] Ex. 43 at 8 (S. DeMerritt Rebuttal).
[256] Ex. 108 at 5 (M. Johnson Surrebuttal).
[257] Ex. 43 at 8 (S. DeMerritt Rebuttal).
[258] Ex. 108 at 5-6 (M. Johnson Surrebuttal).

N. Revenue Requirements Summary

229. With the adjustments to the rate base and test year operating expenses and revenues agreed to by the parties through the course of testimony exchanged in this proceeding, MERC calculates the gross revenue deficiency to be $14,992,107. The Department calculates the gross revenue deficiency to be $12,542,974.[259]

230. These numbers are approximate, and because of the changes from the initial filing, the numbers need to be recalculated to reflect the agreement of the parties as well as the recommendations of the ALJ as to certain issues and the recommended return on common equity established in these findings. As a result, while an estimated figure is provided in these findings, the concepts embodied in these findings should govern. The Commission is in a better position to produce a final calculation of the revenue deficiencies once it makes its final determination in this case.

IV. Conservation Improvement Program and Cost Recovery Mechanisms

A. Rate case requirements

231. If a utility filing in a general rate case does not have an approved conservation improvement plan (CIP) on file with the Department, that utility must include one in its general rate case notice, pursuant to Minn. Stat. § 216B.241.[260]

232. CIP plans filed by MERC-PNG and MERC-NMU for 2010-2012 were approved by the Department in Docket Nos. G011/CIP-09-800 and G007/CIP-09-803, respectively.[261]

233. The ALJ finds that MERC has satisfied the requirement specified in Minn. Stat. §216B.16, subd. 1.[262]

234. The Legislature requires utilities to make certain CIP expenditures pursuant to Minn. Stat. § 216B.241, and it has established a requirement for cost recovery of these expenses in utility rates. Minn. Stat. § 216B.16, subd. 6b, mandates recovery of CIP expenses in utility rates, and allows a public utility to file rate schedules providing for annual recovery of the cost of CIP programs.

235. Specifically, Minn. Stat. § 216B.16, subd. 6b(a), allows utilities to recover costs of relevant conservation improvements:

> Except as otherwise provided in this subdivision, all investments and expenses of a public utility…incurred in connection with energy conservation improvements shall be recognized and included by the commission in the

[259] Department Summary of Issues at Schedule 3 (Dec. 14, 2011).
[260] Minn. Stat. § 216B.241 (Subd. 1), *and see* Ex. 103 at 2 (Minder Direct).
[261] Ex. 103 at 3 (Minder Direct).
[262] *Id.*

> determination of just and reasonable rates as if the investments were directly made or incurred by the utility in furnishing utility service.

Thus, in a rate case, when CIP expenses are included in test year expenses, a CCRC is calculated by dividing the Commission-approved test year CIP expenses by the Commission-approved test year sales.[263]

236. In MERC's last rate case, for MERC-PNG the Commission approved CIP expenses in the test year of $2,786,388 based on the approved 2008 CIP budget of $1,754,324 plus a CIP tracker balance of $1,032,064 (which was based on a three-year amortization of the December 31, 2007 tracker balance of $3,096,192). The Commission also approved a CCRC for MERC-PNG of $0.00652 per therm, which was calculated by dividing the Commission-approved test year CIP expenses of $2,786,388 by the Commission-approved forecasted test year sales (adjusted to exclude test year volumes attributable to CIP-exempt customers) of 427,446,657 therms.[264]

237. For MERC-NMU, the Commission approved $793,548 in CIP expenses in the test year based on the approved 2008 CIP budget of $479,732 plus a CIP tracker balance of $313,816 (based on a three-year amortization of the CIP tracker balance). The Commission also approved a CCRC for MERC-NMU of $0.00962 per therm, which was calculated by dividing the Commission-approved test year CIP expenses of $793,548 by the Commission-approved forecasted test year sales (adjusted to exclude volumes attributable to CIP-exempt customers) of 82,517,844 therms.[265]

238. Minnesota law also allows for rates to be adjusted for changes in CIP costs that occur after rates are approved in a rate case through an annual recovery mechanism. Pursuant to Minn. Stat. § 216B.16, subd. 6b(c), the Commission may permit a public utility to file rate schedules for annual recovery of the cost of energy conservation improvements. CIP expenses are accounted for using a "tracker," which is an accounting mechanism to accumulate annual expense for future recovery purposes. The Commission has allowed the annual recovery mechanism to allow gradual rate changes to occur, rather than the infrequent but potentially larger changes that can result from rate case recovery. If a utility's actual CIP expenses exceed the utility's level of recovery via the approved CCRC, a Conservation Cost Recovery Adjustment (CCRA) – an annual recovery mechanism – charged outside of a rate case proceeding, is increased.[266]

239. In the 2008 rate case, MERC received Commission approval to implement a CCRA factor to recover, on an annual basis, the amount by which actual CIP

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[263] Ex. 104 at 4 (B. Minder Direct).
[264] Ex. 104 at 4-5 (B. Minder Direct).
[265] Ex. 104 at 5 (B. Minder Direct).
[266] Ex. 104 at 6 (B. Minder Direct).

expenditures are different from the amount recovered through the CCRC factor plus the amount of any Commission-approved CIP financial incentive.[267]

240. The Commission initially set the CCRA factors for MERC-NMU and MERC-PNG at $0.0000 per therm in 2008. MERC's request to update the CCRA factors set in the last rate case was approved by the Commission in Docket Nos. G011/M-10-407 and G007/M-10-409 on October 11, 2010. The current CCRA factor is $0.02715 per therm for MERC-NMU and $0.01719 for MERC-PNG. MERC implemented these CCRAs on November 1, 2010.[268]

B. CIP Tracker Account Balances

241. MERC has expenses in its tracker accounts for MERC-PNG and MERC-NMU, but MERC is not seeking recovery of these balances in this docket. Instead, MERC proposed to recover the unamortized balance via the CCRA.[269] MERC included only its CIP budgets in the test year in the present docket to calculate a revised CCRC.[270]

242. Because of unusual circumstances in the concurrent CIP proceedings in Dockets 10-407 and 10-409, the Department recommended the Commission accept MERC's request not to true-up its CIP tracker balances in this proceeding.[271]

C. Test Year CIP Expenses

243. MERC proposed to include CIP expenses in the Company's base rates via the test year in this proceeding. MERC proposed to include in the test year CIP expenses of $6,737,189 for MERC-PNG (MERC-PNG's 2011 approved CIP budget) and $1,717,238 for MERC-NMU (MERC-NMU's 2011 approved CIP budget) for a total consolidated level of test year CIP expenses of $8,454,427.[272]

244. The Department concluded that MERC's proposed recovery of test year CIP expenses is reasonable and recommended that the Commission allow MERC to include in the test year consolidated CIP expenses of $8,454,427.[273]

D. Allocation of Test Year CIP Expenses

245. MERC proposed to divide the total amount of CIP costs for MERC-PNG and MERC-NMU by the 2011 test year sales volumes, excluding the test year sales volumes for CIP-exempt customers.[274]

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[267] Ex. 41 at 40-41 (S. DeMerritt Direct).
[268] Ex. 41 at 41 (S. DeMerritt Direct); Ex. 104 at 7 (B. Minder Direct).
[269] Ex. 41 at 42 (S. DeMerritt Direct).
[270] Ex. 104 at 9 (B. Minder Direct).
[271] Ex. 104 at 11 (B. Minder Direct).
[272] Ex. 104 at 12 (B. Minder Direct).
[273] Ex. 104 at 13 (B. Minder Direct).
[274] Ex. 41 at 41-42 (S. DeMerritt Direct).

246. The Department recommended the Commission approve the volumetric method of allocating CIP expenses as MERC proposes.[275]

E. Carrying Charges for CIP Tracker Accounts

247. MERC proposes that carrying charges be applied to the CIP tracker accounts for MERC-PNG and MERC-NMU. The Company proposes that at the conclusion of this proceeding, the carrying charges assessed to the CIP tracker accounts be equal to that of the authorized rate or return in the instant case. MERC proposed that the carrying charges apply to the entire CIP tracker account balances, including the 2005, 2006, and 2007 financial incentives.[276]

248. The Department recommended that the Commission allow MERC to apply carrying charges equal to the approved overall rate of return to its CIP tracker accounts, except to any portion of the 2005, 2006 and 2007 DSM financial incentives. The Department recommended that the revised carrying charge be implemented with the final rates in this proceeding.[277]

249. MERC agreed with the Department's recommendation regarding its request for CIP tracker carrying-charges.[278]

F. CIP- Exempt Customers

250. A "CIP-exempt customer" is a customer that has been granted an exemption by the Commissioner of the Department from paying for, or participating in, the CIP projects offered by the utility providing retail electric or gas service to that facility, pursuant to Minn. Stat. § 216B.241. MERC also refers to these customers as "CIP opt-out customers."[279]

G. Uncollected CCRC Revenues

251. In responding to the Department's discovery requests in this proceeding, MERC discovered that in preparing its initial filing, it inadvertently excluded sales from three non-exempt customers in the Company's original calculations of the proposed CCRC, resulting in an overstatement of the CCRC factor. Specifically, MERC incorrectly assumed that one MERC-PNG SLV Interruptible customer and two MERC-NMU SLV Interruptible customers were CIP-exempt customers.[280]

252. In preparing its rate case filing, MERC assumed CIP opt-out customers were synonymous with SLV customers. MERC's assumption was reflected in the rate

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[275] Ex. 104 at 18 (B. Minder Direct).
[276] Ex. 41 at 42-43 (S. DeMerritt Direct); Ex. 104 at 13 (B. Minder Direct).
[277] Ex. 104 at 16 (B. Minder Direct).
[278] Ex. 43 at 30 (S. DeMerritt Rebuttal).
[279] See Ex. 104 at 5 (B. Minder Direct).
[280] Ex. 104 at 18-19 (B. Minder Direct); Ex. 43 at 22-23 (S. DeMerritt Rebuttal).

design and tariffs approved in MERC's 2008 rate case, which set distribution charges for this customer class without including a CCRC.[281]

253. MERC also realized that the CCRC factors were incorrectly calculated in its last rate case in Docket No. G007,011/GR-08-835. In that case, MERC calculated the CCRC factors for MERC-PNG and MERC-NMU by taking test year approved CIP costs and dividing by test year approved sales volumes less sales volumes attributed to MERC's CIP-exempt customers. MERC incorrectly assumed, however, that these same SLV Interruptible customers (one MERC-PNG and two MERC-NMU customers) were CIP-exempt customers. These three customers are the only SLV customers on MERC's system that have not obtained a CIP exemption from the Department under Minn. Stat. § 216B.241. MERC, believing these customers were exempt, did not include the volumes from these customers in its calculation of the CCRC factors for MERC-PNG and MERC-NMU.[282]

254. Additionally, the distribution rates established for these customers in MERC's last rate case incorrectly excluded the CCRC factors established by the Commission. The distribution rate for MERC-PNG's SLV Interruptible customers was set at $0.00420 per therm, while the CCRC factor approved by the Commission was $0.00652 per therm. The distribution rate for MERC-NMU's SLV Interruptible customers was set at $0.000850 per therm, while the CCRC factor approved by the Commission was $0.00962 per therm. These distribution rates and CCRC factors set by the Commission went into effect on January 1, 2010.[283]

255. The CCRC factors were calculated correctly in Aquila's 2000 rate case in Docket No. G007,011/GR-00-951. Based on the calculations in Aquila's August 28, 2003, Compliance Filing in that docket, it appears that Aquila included the volumes for the SLV customers that are not CIP-exempt. The Commission approved the resulting CCRC factors of $0.00329 per therm for MERC-PNG and $0.00280 per therm for MERC-NMU in its November 21, 2003 Order in that docket. The Commission also approved distribution rates of $0.00400 per therm for MERC-PNG's SLV customers and a distribution rate of $0.00850 per therm for MERC-NMU's SLV customers. These rates were in effect when MERC acquired Aquila's Minnesota natural gas operations on July 1, 2006.[284]

256. Though the CCRC factors were calculated correctly in the 2000 rate case, MERC also believes that Aquila did not credit the MERC-NMU CIP tracker account for CCRC revenues attributable to the CIP-non-exempt customers at issue. Though the CCRC factors were calculated correctly, those factors were never included in the distribution rates charged to MERC-PNG's and MERC-NMU's SLV Interruptible rate class. In other words, the distribution rates for this rate class did not include the CCRC factor, even though some of the customers within the class were not CIP-exempt. To properly account for the CCRC factor, the class should have been split between CIP-

[281] Ex. 104 at 19 (B. Minder Direct).
[282] Ex. 43 at 22-23 (S. DeMerritt Rebuttal).
[283] Ex. 43 at 23 (S. DeMerritt Rebuttal).
[284] Ex. 43 at 23-24 (S. DeMerritt Rebuttal).

exempt and CIP-non-exempt, and the distribution charge for the CIP-non-exempt customers should have included the CCRC factor.[285]

257. In discovery, MERC identified the uncollected CCRC revenues associated with each of these customers from May 2005 through February 2010. MERC identified $61,446 in uncollected CCRC revenues attributable to the MERC-PNG CIP-non-exempt customer and $862,089 in uncollected CCRC revenues attributable to the MERC-NMU CIP-non-exempt customers.[286]

258. In discovery MERC also identified that neither of the two CIP-non-exempt MERC-NMU SLV Interruptible customers have participated in any CIP projects since MERC acquired Aquila's operations in July 2006.[287]

259. The Department recommended that, because these three customers' sales volumes should have been included in the calculation of the approved CCRCs for MERC-PNG and MERC-NMU, the revenue be imputed to the CIP tracker and that the CCRC be revised prospectively. Specifically, the Department recommended that MERC credit the MERC-PNG CIP tracker account $61,446 and the MERC-NMU CIP account $862,089.[288]

260. In rebuttal testimony, MERC clarified that it has credited the MERC-PNG CIP tracker account for CCRC revenues attributable to the SLV Interruptible customer since July 1, 2006. MERC continued to credit the CIP tracker account for CCRC revenues attributable to this customer following implementation of final rates in Docket No. G007,011/GR-08-835, even though the CCRC factor was higher than the distribution rate established for this customer.[289]

261. In addition, the Company believes Aquila also credited the MERC-PNG CIP tracker for CCRC revenues attributable to this customer because MERC continued Aquila's billing practices following its acquisition of Aquila's operations in 2006.[290]

262. Therefore, because MERC has already credited the MERC-PNG CIP tracker account for the CCRC revenues attributable to this customer, it disagreed with the Department's recommendation that the Company credit the MERC-PNG CIP tracker account by $61,446 for CCRC revenues attributable to the CIP-non-exempt MERC-PNG SLV Interruptible customer.[291]

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[285] Ex. 43 at 23-25 (S. DeMerritt Rebuttal); *see also* Ex. 81 at 7 (G. Walters Rebuttal) In Rebuttal testimony, MERC proposed that the distribution rates established in this proceeding for the three SLV Interruptible customers who are not CIP-exempt be calculated to include the CCRC factor approved by the Commission in this proceeding.
[286] Ex. 104 at 20 and Schedule (BJM-6) (B. Minder Direct).
[287] Ex. 104 at Schedule (BJM-6) (B. Minder Direct).
[288] Ex. 104 at 19-20 (B. Minder Direct).
[289] Ex. 43 at 23-24 (S. DeMerritt Rebuttal); Ex. 104 at Schedule (BJM-6) (B. Minder Direct).
[290] Ex. 43 at 24-25 (S. DeMerritt Rebuttal); Ex. 104 at 8-13 and Schedule (BJM-6) (B. Minder Direct).
[291] Ex. 43 at 25-26 (S. DeMerritt Rebuttal).

263. In surrebuttal testimony, the Department withdrew its recommendation to have MERC credit the MERC-PNG CIP tracker account by $61,446 for CCRC revenues attributable to the one CIP-non-exempt MERC-PNG SLV Interruptible customer.[292]

264. Regarding the MERC-NMU CIP tracker account, MERC has not credited that account for any CCRC revenues before the implementation of final rates from the 2008 rate case on January 1, 2010. MERC has proposed to credit the CIP tracker for these two CIP-non-exempt customers from January 1, 2010, through the implementation of final rates in this docket to account for the CCRC factors that were incorrectly calculated by MERC by excluding test year sales volumes for these two customers. This amount is $448,526 for the period January 1, 2010, through April 2011.[293]

265. The Department recommends MERC credit the MERC-NMU CIP tracker for CCRC revenues attributable to these two customers from May 2005 through February 2011.[294] In addition, the Department recommended that any CCRC revenues that will not be collected from these customers from March 2011 through implementation of final rates in this docket be added to the Department's recommended credit amount of $862,089.[295]

266. The OAG made no recommendation regarding the amount MERC should credit the MERC-NMU CIP tracker. The OAG recommended that the Commission take formal notice that the CIP tracker balance is incorrect and order that measures be taken to correct the tracker balance in the appropriate regulatory forum.[296]

267. The Department and MERC did not reach agreement on the treatment of the two CIP-non-exempt MERC-NMU SLVI customers.[297]

268. MERC argued that the Company should not be required to credit the MERC-NMU CIP tracker account for any CCRC revenues prior to implementation of final rates on January 1, 2010, in Docket No. 0007,011/GR-08-835.[298] MERC instead proposed that the Company credit the CIP tracker account for $448,526, the amount of revenue attributable to the two non-CIP-exempt MERC-NMU SLVI customers from January 1, 2010 through April 2011, plus CCRC revenue attributable to these two customers from May 2011 through the implementation of final rates in this docket.[299] MERC's proposed $448,526 credit reflects the revenue not collected from these two MERC-NMU customers for the period January 1, 2010, up to the implementation of final rates in this docket.[300]

[292] Ex. 105 at 9 (B. Minder Surrebuttal).
[293] Ex. 43 at 26-27 (S. DeMerritt Rebuttal).
[294] Ex. 104 at 18-21 (B. Minder Direct).
[295] Ex. 105 at 13 (Minder Surrebuttal); and Ex. 106 at 6 (Minder Additional Rebuttal).
[296] Ex. 96 at 56-57 (V. Chavez Direct).
[297] Ex. 43 at 25 (DeMerritt Rebuttal).
[298] Ex. 43 at 26 (DeMerritt Rebuttal).
[299] *Id.* at 27.
[300] *Id.* at 27-28.

269. The Department argued that it is not reasonable for MERC's ratepayers to pay for the Company's error. Although the CCRC for MERC-NMU was correctly calculated in the 2000 rate case, MERC and apparently Aquila did not charge these two non-CIP-exempt customers the CCRC approved in that docket. In addition, MERC continued not to charge these two customers the CCRC approved in the 2008 rate case. The fact that these customers have not participated in CIP since July 1, 2006 when MERC took over the Minnesota gas operations from Aquila is irrelevant. The Commission's longstanding policy is to have all non-CIP-exempt customers contribute to CIP costs recovery since these customers experience system-wide benefits provided by CIP. MERC has not provided a reasonable basis for deviating from this policy.[301]

270. The ALJ finds that MERC has not established by a preponderance of the evidence that it is reasonable to collect from all non-exempt customers the amount that the Company and Aquila failed to properly collect from two SLV customers. Such a result is not consistent with the requirement in Minn. Stat. § 216B.03 that requires the Commission to resolve all doubts as to reasonableness in favor of the consumer.

H. Calculation of CCRCs

271. MERC proposes a consolidated CCRC of $0.01513 per therm.[302]

272. The Department recommended the Commission approve a revised CCRC factor based on the Company's proposed volumetric method and test year sales approved by the Commission and to include in the calculation of the CCRC the sales from all customers that are not exempted from CIP.[303]

273. MERC agreed with the Department's recommendation. In particular, MERC agreed that the volumes from the three customers discussed above should be included in the calculation of the CCRC factor.[304]

I. Calculation of CCRAs

274. MERC did not propose to update the CCRA factors in this proceeding. The Department found MERC's proposal not to update the CCRAs reasonable, but recommended that if the Commission approves consolidation of the CCRCs in the instant proceeding, MERC should seek consolidation of the CCRAs.[305]

J. CIP Consolidation

275. MERC proposes to consolidate both the CCRC and CCRA factors for MERC-NMU and MERC-PNG in this proceeding consistent with its request for overall rate consolidation. Following consolidation of the rate areas, it would no longer make

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[301] Ex. 105 at 12-13 (Minder Surrebuttal).
[302] Ex. 104 at 18 (B. Minder Direct).
[303] Ex. 105 at 4 (B. Minder Surrebuttal).
[304] Ex. 43 at 28 and Schedule (SSD-7) (S. DeMerritt Rebuttal).
[305] Ex. 104 at 22 (B. Minder Direct).

sense for MERC to have two separate CIP programs, and MERC therefore will request approval to consolidate the CIPs for MERC-PNG and MERC-NMU, including the CIP tracker accounts, CCRC and CCRA factors, and DSM financial incentives.[306]

276. MERC-NMU's CIP program is virtually identical to MERC-PNG's CIP program and it will be straightforward to combine the two programs.[307] Consolidation of the CIP programs for MERC-PNG and MERC-NMU will result in greater efficiencies in the development and administration of the programs.[308]

277. The Department is responsible for approving MERC's CIP pursuant to Minn. Stat. § 216B.241. The Commission, however, has the authority to approve CIP cost recovery and financial incentives under Minn. Stat. § 216B.16, subd. 6b and 6c. Therefore, following the rate area consolidation, MERC will seek approval from the Department of a consolidated CIP.[309]

278. MERC has proposed a single consolidated CCRC factor in this proceeding based on combined test year CIP expenses.[310]

279. Finally, MERC requests the Commission's approval of a consolidated financial incentive mechanism, which would apply to the first CIP year following rate area consolidation and consolidation of the CIP for MERC-NMU and MERC-PNG. The Commission approved new financial incentive mechanisms for MERC-NMU and MERC-PNG on January 27, 2010, in Docket No. E, G-999/CI-08-133. The financial incentive model is the same for both MERC-NMU and MERC-PGN and uses the same calibration point. Consolidating the financial incentives for MERC-NMU and MERC-PNG should pose no problems following CIP consolidation.[311]

280. MERC provided a timetable of its proposed consolidation plan in response to the Department's discovery request. The Department recommended the Commission approve MERC's proposed CIP consolidation timetable.[312]

281. The consolidation of the CIP programs will make the administration of the program more efficient. In response to the Department's discovery requests, MERC identified savings of $42,493 for activities that would benefit from combining MERC-PNG and MERC-NMU.[313]

282. The Department initially recommended that MERC reduce its CIP tracker by $42,493 in 2012 to account for the expected savings to the CIP programs,[314] but

[306] Ex. 41 at 44 (S. DeMerritt Direct).
[307] Ex. 41 at 44 (S. DeMerritt Direct).
[308] Ex. 41 at 44 (S. DeMerritt Direct).
[309] Ex. 41 at 44-45 (S. DeMerritt Direct).
[310] Ex. 41 at 45 (S. DeMerritt Direct).
[311] Ex. 41 at 45 (S. DeMerritt Direct).
[312] Ex. 104 at 25 and Schedule (BJM-9) (B. Minder Direct).
[313] Ex. 112 at 23 (M. St. Pierre Direct).
[314] Ex. 112 at 24 (M. St. Pierre Direct).

withdrew its recommendation for MERC to reduce the CIP tracker at the evidentiary hearing.[315]

283. MERC's proposal to consolidate the MERC-PNG and MERC-NMU CIP programs, including the CIP tracker accounts, CCRC and CCRA factors, and DSM financial incentives, is reasonable and should be approved.

V. RATE DESIGN

284. In the rate design portion of a general rate case, the Commission determines what portion of the revenue requirement should be met by the various customer classes that receive service from the utility company. This division of responsibility for producing the required revenues among the customer classes is called revenue apportionment. In addition to revenue apportionment, the Commission considers how to design the rates within each customer class to collect the amount of revenue that has been apportioned to that class.

285. As a starting point, the Commission utilizes an analysis of the class cost of service, which evaluates both the cost imposed by each customer class as a whole, and also determines the cost of each relevant component of service that is separately charged by the Company's tariffs.

286. In the rate design phase of the proceeding, the Commission considers cost, as well as other non-cost factors, in designing final rates for the utility. These rates must be designed to recover the revenue requirement that has been determined for the utility, and thus when non-cost factors are applied to reduce a rate for one class, the revenues need to be collected in some manner from other customer classes. Similarly, when different types of costs imposed by one class of customers are not recognized in one part of that customer class's rates, those costs must then be recovered by other components of that customer class's rates.

A. Class Cost of Service Study

287. The purpose of a CCOSS is to identify the revenues, costs, and profitability for each class of service, as required by Minn. R. 7825.4300(C).[316] The CCOSS analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes.[317]

288. In its initial filing, MERC presented its CCOSS for MERC-PNG, MERC-NMU and MERC-Consolidated. These CCOSS applied general principles of cost allocation from both NARUC and the American Gas Association to arrive at estimated

[315] Hearing Transcript, Vol. 1 at 121-123 (S. DeMerritt); Vol. 2 at 161-162 (M. St. Pierre).
[316] Citation to Minnesota Rules refers to the 2010 Edition.
[317] Ex. 58 at 6 (J. Hoffman Malueg Direct).

costs of service for the various customer classes and individual components of cost within each customer class.[318]

289. No other party presented a CCOSS in this case.

290. The Department reviewed the CCOSS filed by MERC and recommended that MERC allocate income taxes on the basis of rate base with certain changes. The Department also recommended that in future rate cases, MERC calculate and allocate income taxes by class on the basis of taxable income by class that fully and only reflect the CCOSS.[319]

291. The Department also recommended that the classification of transmission lines be based upon the Minimum Size methodology and the classification and allocation of FERC Accounts 302, 303, 374, and 375 be based upon Distribution Plant, as described in the NARUC Gas Manual.[320]

292. MERC agreed to the Department's recommendations.[321] MERC provided an update to the six CCOSS for the 2011 proposed test year in sur-surrebuttal testimony. Specifically, MERC updated the revenue requirements to reflect the changes made in Mr. DeMerritt's sur-surrebuttal testimony; the classification of transmission mains based upon the Minimum Size Methodology, and the classification and allocation of FERC Accounts 302, 303, 374, and 375 on the basis of Distribution Plant, as described in the NARUC Gas Manual.[322]

293. Given the Department's recommendations on the allocation of income taxes by class, MERC requests that the Commission's Order reflect the modification that MERC is no longer required to file a CCOSS that allocates income taxes on the basis of taxable income attributable to each customer class, but rather, that allocation of income taxes shall be done on the basis of taxable income by class that fully and only reflects the CCOSS.[323]

294. MERC and the Department have resolved all issues relating to the CCOSS.[324]

295. The OAG expressed concerns about the use of fully embedded CCOSS for assigning costs to customer classes and establishing rates within those classes.[325]

[318] Ex. 58 (J. Hoffman Malueg Direct).
[319] Ex. 116 at 1-7 (S. Ouanes Rebuttal); Ex. 115 at 5-6, 15 (S. Ouanes Direct).
[320] Ex. 116 at 4-5 (S. Ouanes Rebuttal); Ex. 121 at 69-71 (A. Heinen Direct); Ex. 122 at 12-14 (A. Heinen Surrebuttal).
[321] Ex. 59 at 23 (J. Hoffman Malueg Rebuttal).
[322] Ex. 61 at 4-41 and Schedules (JCHM-1 – JCHM-7) (J. Hoffman Malueg Sur-Surrebuttal).
[323] Ex. 60 at 3 (J. Hoffman Malueg Surrebuttal).
[324] Hearing Transcript Vol. 1 at 133 (J. Hoffman Malueg).
[325] Ex. 100 at 23-27 (J. Lindell Direct).

The OAG argued that reliance on a fully distributed CCOSS does not provide the proper considerations of economic efficiency and environmental protection in setting rates.[326]

296. In his direct testimony, Mr. Lindell presented excerpts from the 1996 Commission Order in Docket No. G-008/GR-95-700, in which statements were made on limitations posed by the use of a fully embedded CCOSS and that the use of marginal cost analyses is more appropriate.[327]

297. The Commission's Order in that docket centered on a proposal made by another utility to position its rate design for a more competitive, deregulated environment, which is not applicable to MERC or to this current rate case proceeding.[328]

298. The OAG also maintained that any claim of subsidy or cost support for a higher customer charge should be rejected because MERC's practice is inconsistent with the NARUC Gas Manual and MERC proposed rates that are not supported by its own CCOSS.[329]

299. MERC supports its use of fully distributed embedded CCOSS, and notes that the Commission has a long history of using fully distributed, embedded CCOSS in setting natural gas rates in Minnesota. MERC's CCOSS fully and correctly demonstrate the embedded fixed costs of residential service. Moreover, calculating a CCOSS involves a degree of judgment and therefore there will not be one singularly correct CCOSS for a utility.[330]

300. Additionally, MERC's CCOSS are developed to allocate the Company's revenue requirements, which are based upon embedded costs.[331]

B. Revenue Apportionment

301. MERC's proposed revenue apportionment considered the following primary objectives:

- collect total revenues sufficient to allow the Company to recover its cost of operations for the test year, including a reasonable return on investment;
- reflect the cost of providing service to each customer class, as supported by the CCOSS, while giving consideration to non-cost factors where appropriate, e.g., value of service;
- provide overall revenue stability to the Company;

[326] Ex. 100 at 25 (J. Lindell Direct).
[327] Ex. 100 at 23-24 (J. Lindell Direct).
[328] *See* Hearing Transcript Vol. 1 at 134-135 (J. Hoffman Malueg).
[329] Ex. 100 at 28-29 (J. Lindell Direct).
[330] Ex. 59 at 3-4, 10-13 (J. Hoffman Malueg Rebuttal); Hearing Transcript Vol. 1 at 135 (J. Hoffman Malueg).
[331] Ex. 59 at 3-4, 10-13 (J. Hoffman Malueg Rebuttal).

- encourage sound economic energy use;
- minimize cross-subsidization between rate classes;
- avoid large bill impacts or "rate shock;"
- limit the impact of the proposed rates on low-income customers; and
- provide flexibility on pricing and service conditions, which will allow the Company's natural gas services to be competitive with other energy sources.[332]

302. The CCOSS was the starting point for the apportionment of the retail revenue requirement among the rate classes. Other rate design goals were then considered, as noted above, such as maintaining competitive pricing for competitive services, and limiting large bill impacts or "rate shock." The Company's goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts.[333]

303. MERC's rate design proposals, including the revenue apportionment, are designed to move customer classes a reasonable amount toward their cost of service, and to equalize the rates assessed to MERC-PNG and MERC-NMU to consolidate the rate areas of these formerly separate utilities.[334]

304. MERC's proposed revenue apportionment was presented in a graphic format that compared current revenues from a customer class to proposed revenues and the revenue that would be justified by a full movement to the cost as indicated by the CCOSS.[335]

305. In additional testimony, MERC provided updated rate design models with updated revenue allocations, consistent with the updated allocations made in Mr. DeMerritt's sur-surrebuttal testimony.[336]

306. The Department reviewed MERC's proposed revenue apportionment, and the rationale offered by MERC for the proposed apportionment, and determined that the apportionment was reasonable. Specifically, the Department recommended adoption of MERC's proposed revenue apportionment as detailed in Table 3 of the direct testimony of Mr. Shaw, and as updated in Table S-1 of Mr. Shaw's surrebuttal testimony.[337]

307. The Department recommended that if the Commission approves a lower revenue requirement than that requested by the Company, the revenue responsibilities

[332] Ex. 80 at 10 (G. Walters Direct).
[333] Ex. 80 at 13 (G. Walters Direct).
[334] Ex. 80 at 13 (G. Walters Direct).
[335] Ex. 80 at 14 and Schedule (GJW-1), Schedule 3, Summary (including gas costs), and Schedule 5, Summary (not including gas costs) (G. Walters Direct).
[336] Ex. 83 at 1-2 and Schedules (GJW-1–GJW-2) (G. Walters Sur-Surrebuttal).
[337] Ex. 118 at 15, 23-25, Table 3 (C. Shaw Direct); Ex. 119 at 3, Table S-1 (C. Shaw Surrebuttal).

for the non-firm classes be held constant, and the remaining revenue requirement be apportioned proportionally to the remaining firm classes.[338]

308. MERC generally agreed with the Department's proposed apportionment of revenue responsibility, but due to an error in the calculation of the proposed conservation cost recovery charge (CCRC), MERC proposed to increase the apportionment of revenue responsibility by $603,458 for MERC's SLV Interruptible customers.[339]

309. The Department agreed with MERC's updated revenue apportionment.[340]

310. No other party filed testimony on the revenue apportionment in this case.

311. The revenue apportionment agreed to by MERC and the Department is reasonable and should be adopted in this proceeding. MERC's proposed revenue apportionment, summarized in Table 3 of Mr. Shaw's direct testimony, should be used as a starting point for determining the final rate design after the Commission has determined the final revenue requirement.

C. Rates

312. The only component of rate design the Department challenged in this proceeding was MERC's proposed customer charges. The distribution volumetric rates and customer charges proposed by MERC in this proceeding for its various customer classes were challenged by other parties in only two instances: the Residential monthly customer charge, and the customer charge for Small Commercial and Industrial (C&I) classes. These two charges are discussed below.

313. MERC and the Department have reached agreement regarding all rate components. The OAG recommends no increase in the monthly customer charge for residential and small class C&I customers, in part, because it does not support MERC"s Class Cost Service Studies (CCOSS) used to support the proposed customer charge increases.

1. Residential Customer Charge

314. MERC's existing residential customer charge is $7.25 per month. MERC proposed to increase the monthly residential customer charge to $9.50 per month.[341]

315. The Department recommended raising the residential customer charge to $8.50 per month. The Department reasoned that the increase to $8.50 would move the residential customer charge closer to cost without resulting in rate shock. The

[338] Ex. 118 at 25 (C. Shaw Direct).
[339] Ex. 119 at 7 (C. Shaw Surrebuttal); Ex. 81 at 4, 7 and Schedule (GJW-1) (G. Walters Rebuttal); Hearing Transcript Vol. 1 at 208-209 (G. Walters).
[340] Ex. 120 at 1-5 and Schedule (CJS-AR-1) (C. Shaw Additional Rebuttal).
[341] Ex. 80 at 16 (G. Walters Direct); Ex. 118 at 26, Table 5 (C. Shaw Direct).

Department further reasoned that the increase is consistent with other increases in residential customer charges.[342]

316. MERC accepted the Department's recommendation that the residential customer charge be increased to $8.50.[343]

317. The OAG recommended retaining the existing residential customer charge.[344]

318. The following chart shows that the current and proposed residential customer charges (as agreed upon by the Department and MERC) are below the cost of service (as updated in MERC witness, Joylyn Hoffman-Malueg's sur-surrebuttal testimony).[345]

	Current Customer Charge	*Proposed Customer Charge*	*Customer Charge Justified by the CCOSS*
MERC-PNG Residential	$7.25	$8.50	$23.72
MERC-NMU Residential	$7.25	$8.50	$27.96

319. The CCOSS shows that the current residential and small C&I customer charges are well below the cost of service for those customer classes.

320. Because the customer charges are below the customer cost, it is necessary to recover the unrecovered customer costs through the distribution charge. As a result, customers with higher than average usage pay more than their proportional share of these costs. The proposed increase in the residential customer charge addresses this inconsistency.[346]

321. A higher customer charge will result in more level winter and summer bills, provides a more accurate price signal to customers by bringing their rates closer to the true cost of service, and provides incrementally more stable cash flow to the utility.[347]

322. An increase in the residential customer charge to $8.50 per month appropriately assigns costs to that class and avoids rate shock. The ALJ recommends that the Commission approve the Department and MERC agreement to increase the residential customer charge to $8.50 per month.

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342 Ex. 118 at 27, Table 6 (C. Shaw Direct); Ex. 119 at 11 (C. Shaw Surrebuttal).
343 *See* Ex. 119 at 11 (C. Shaw Surrebuttal).
344 Ex. 100 at 38 (J. Lindell Direct).
345 Ex. 119 at 11 (C. Shaw Surrebuttal); Ex. 80 at 16-17 and Schedule (GJW-1) (G. Walters Direct); Ex. 61 at Schedule (JCHM-2) at 97 and (JCHM-1) at 33.
346 Ex. 80 at 16-21 (G. Walters Direct).
347 Ex. 80 at 17-19 (G. Walters Direct).

2. Customer Charges for Larger Customers

323. MERC proposed to increase the customer charges for its larger customers, including the Small C&I, Large C&I, Small Volume Interruptible (SVI), Large Volume Interruptible, and SLV customers. In addition, MERC proposed a monthly charge for the SLV Town Plant Transportation rate class, and to decrease the administrative charge for that class per metered account.[348]

324. The Department recommended that the charges for larger customers be increased to better coincide with costs.[349]

325. MERC accepted the Department's customer charge recommendations with the exception of the Department's proposal regarding the SLV customers. The Department recommended that the customer charge for the SLV Customers decrease from $300 to $250. MERC disagreed with that recommendation because if the customer charge is kept at $300, the distribution charge for the SLV class can remain the same. The customers in the SLV class prefer to keep the distribution charge the same and increase the customer charge.[350]

326. Because the small number of customers in the SLV class conveyed their preference to MERC regarding the class rate design, the Department accepted MERC's proposal for this class. The table below shows the customer charge justified by the CCOSS (as consolidated), MERC's proposed customer charges, and the charges agreed upon by MERC and the Department.[351]

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[348] Ex. 80 at 15-33 and Schedules (GJW-1 and GJW-2) at Schedules 1 and 2 (G. Walters Direct).
[349] *See* Ex. 119 at 9-10, Table S-2 (C. Shaw Surrebuttal).
[350] Ex. 81 at 11 (G. Walters Rebuttal).
[351] Ex. 81 at Schedule (GJW-2) (G. Walters Rebuttal); Ex. 118 at 26-27, 33 (C. Shaw Direct); Ex. 119 at 9-10, Table S-2 (C. Shaw Surrebuttal).

	Charge Justified by CCOSS	Current Customer Charge	MERC Proposed Customer Charge	Charge Agreed to by MERC and Department
General Service Residential Consolidated Sales	$24.85	$7.25	$9.50	$8.50
General Service Small Commercial & Industrial Consolidated Sales	$27.92	$12.00	$14.50	$14.50
General Service Large Commercial & Industrial Consolidated Sales	$66.28	$17.00	$19.50	$35.00
Small Volume Interruptible Consolidated Sales	$221.67	$80.00	$85.00	$150.00
Large Volume Interruptible Consolidated Sales	$236.05	$160.00	$175.00	$175.00
Super Large Volume Town Plant Transportation	$186.81	$160.00	$300.00	$300.00

327. In addition, the Department agreed with MERC's proposal to reduce the Transportation Administration Fee from $170 to $70.[352]

328. The OAG recommended no increase to the customer charge for the Small C&I class.[353]

329. MERC's proposed increase to the customer charges for larger customers, including its proposal to decrease the transportation administration fee is supported by the CCOSS. The Commission should adopt the proposed customer charges, as agreed to by MERC and the Department.

[352] Ex. 81 at 15 (G. Walters Rebuttal); Ex. 119 at 11 (C. Shaw Surrebuttal).
[353] Ex. 100 at 38 (J. Lindell Direct).

VI. Tariff Changes

330. MERC's filing proposed multiple tariff changes. Specifically, MERC proposed tariff changes to address the proposed consolidated rate design; switching between Firm Sales, Interruptible Sales, and Transportation classes of service; and the exclusion of farm tap customers from the telemetry requirement, among other miscellaneous changes. These changes were displayed in red-line form in the original filing, and discussed in MERC's direct testimony.[354]

331. In response to Department discovery requests, MERC provided a matrix that identified each proposed tariff change, the location of each proposed change in the tariff, a brief description of each of the proposed tariff changes, a summary of the rationale for each proposed tariff change, and the Company witness sponsoring each proposed change.[355]

332. The Department reviewed the requested tariff changes and recommended approval of all of them, except as specifically discussed in the testimony of Department witnesses Mr. Shaw and Mr. Minder.[356]

333. The Department also recommended that MERC modify its flexible rate service rider to require a minimum rate of $0.0045.[357] MERC agreed with the Department's proposed increase to the minimum flexible rate in the Company's Flexible Rate Tariff.[358]

334. Mr. Shaw's recommendations related to rate design issues that were previously discussed herein. Mr. Minder recommended that the Commission approve each of MERC's proposed tariff changes as identified in Exhibit (BJM-13) of his direct testimony.[359] MERC agrees with Mr. Minder's recommendation and the tariff changes proposed by MERC, as identified in Exhibit BJM-13 to Mr. Minder's direct testimony should be approved.[360]

VII. DISTRIBUTION RATE AREA AND PGA CONSOLIDATION

A. Distribution Rate Area Consolidation

335. MERC is requesting distribution rate area consolidation of its current MERC-PNG service territory and its MERC-NMU service territory such that all

[354] Ex. 80 at 52-58 (G. Walters Direct); Ex. 1, Notice of Change in Rates, Interim Rate Petition, Proposed Final Tariffs – Redline (Nov 30, 2010); Hearing Transcript Vol. 1 at 203-208 (G. Walters).
[355] Ex. 104 at 31 and Schedule (BJM-13) (B. Minder Direct).
[356] Ex. 104 at 31 and Schedule (BJM-13) (B. Minder Direct).
[357] Ex. 118 at 23 (C. Shaw Direct).
[358] Ex. 81 at 4 (G. Walters Rebuttal).
[359] Ex. 104 at 31 (B. Minder Direct).
[360] Ex. 105 at 14-15 (B. Minder Surrebuttal).

customers in the same classes will have the same fixed charge and distribution charge for all customer classes in MERC's rate schedules.[361]

336. Under MERC's consolidation proposal, MERC would continue to have the same types of rate classes: General Service – Residential; General Service – Small C&I; General Service – Large C&I; Small Volume Interruptible; Large Volume Interruptible; and SLV e Interruptible. MERC proposes to eliminate the Large Volume Interruptible Main Line rate class and combine the MERC-NMU Large Volume Interruptible Main Line rate class with the MERC-NMU Large Volume Interruptible Town Plant rate class.[362]

337. MERC proposed that the rate schedules match the proposed Purchased Gas Adjustment (PGA) consolidation,[363] discussed below.

338. The MERC-PNG and MERC-NMU service areas are contiguous and are served by the same company (and were for many years before MERC acquired them). The two areas have been operating as one company since MERC took ownership in 2006. The same services and service levels are provided in the two areas, they are supported by the same MERC staff, and served by the same call center. From an operations perspective, MERC is a single utility. MERC proposes distribution rate consolidation of the current MERC-PNG and MERC-NMU rate areas into a single distribution rate area.[364]

339. In its last rate case, MERC proposed as part of its rate design that the customer charges of MERC-PNG and MERC-NMU be set at the same level, and that the respective distribution rates be moved closer together for each customer class, to facilitate a future decision to fully consolidate the distribution rate schedules for MERC-PNG and MERC-NMU. The Commission approved those requests.[365]

340. MERC-PNG and MERC-NMU already have the same customer charges, submit filings to the Commission as a consolidated entity, and have their capital structure and return on equity evaluated on a consolidated basis.[366]

341. Consolidation will eliminate any customer confusion regarding differences between MERC-PNG and MERC-NMU rates and eliminate the necessity of allocating costs between the two entities.[367]

342. The consolidation of the two entities would have little to no impact on the average monthly customer bills. MERC provided a table in the direct testimony of Greg Walters that showed the bill impacts for a residential customer of the proposed distribution consolidation without the effects of the proposed rate increase. The

[361] Ex. 80 at 3-9 (G. Walters Direct); Ex. 41 at 48 (S. DeMerritt Direct).
[362] Ex. 80 at 3-8, 12 (G. Walters Direct).
[363] Ex. 80 at 12 (G. Walters Direct).
[364] Ex. 19 at 4-5 (C. Cloninger Direct).
[365] Ex. 19 at 5 (C. Cloninger Direct).
[366] Ex. 118 at 24-25 (C. Shaw Direct).
[367] Ex. 118 at 25 (C. Shaw Direct).

information shows that due to consolidation, the average monthly bill for MERC-PNG customers would increase $0.66, and the average monthly bill for MERC-NMU customers would decrease by $2.40.[368]

343. The Department provided a table in the direct testimony of Chris Shaw that showed the overall effect on each class due to the consolidation and proposed rate increase.[369] Based on these two tables, the Department concluded that MERC's proposed distribution area consolidation would have a minimal impact on rates while allowing MERC to consolidate its distribution entities to reflect that the non-gas portion of its system is operated as one entity.[370]

344. Because of "the benefits of consolidation, the fact that the non-gas portion of MERC's system is operated as a single entity and the minimal impact on customer rates," the Department recommended that MERC consolidate the MERC-PNG and MERC-NMU as a single entity for gas distribution.[371]

345. MERC's proposed consolidation plan is reasonable and the Commission should approve the consolidation of MERC-PNG and MERC-NMU into a single distribution rate area.

B. PGA Consolidation

346. MERC is requesting distribution rate area consolidation of its MERC-PNG service territory and its MERC-NMU service territory such that all residential customers will have the same fixed charge and distribution charge, all Small C&I customers will have the same fixed charge and distribution charge, and so forth for all other customer classes in MERC's rate schedules.[372]

347. MERC is also requesting the consolidation of the four PGA systems currently in place (PNG-NNG, PNG-VGT, PNG-GLGT, and NMU) into two new PGAs, the MERC-NNG PGA system and the MERC-Consolidated PGA system.[373]

348. MERC proposes to change the PGA areas from four to two to more accurately reflect the commodity cost of gas for its customers served by different pipelines. The historic NMU PGA determines the cost of gas by consolidating the cost of gas among the four pipelines that provide gas to MERC-NMU customers. The historic PNG PGAs determine a separate cost of gas for each of the three pipelines that provide gas to MERC-PNG customers. This method results in MERC-PNG and MERC-NMU customers paying a different cost of gas even when their gas comes from the same pipeline.[374]

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[368] Ex. 80 at 43 (G. Walters Direct).
[369] Ex. 118 at 15-20 (Table 3) (C. Shaw Direct).
[370] Ex. 118 at 24 (C. Shaw Direct).
[371] Ex. 118 at 24-25 (C. Shaw Direct).
[372] Ex. 41 at 48 (S. DeMerritt Direct).
[373] *Id.*
[374] Ex. 19 at 5 (C. Cloninger Direct).

349. MERC proposes to consolidate the PGAs of MERC-NMU and MERC-PNG, and employ two PGA areas, one for the northern pipelines that serve Minnesota from Canada, and one for the customers served off the Northern Natural Gas (NNG) pipeline.[375] The current MERC-NNG PGA system along with the current MERC-NMU PGA system customers served by the NNG will constitute the new MERC-NNG PGA system. The remaining customers of the MERC-NMU PGA system along with the customers on the PNG-VGT PGA system and the PNG-GLGT PGA system will be grouped together in the new MERC-Consolidated PGA system.[376]

350. This proposed consolidation will have no impact on revenues.[377]

351. All margin revenues based on current rates related to fixed charges, distribution rates, and daily firm capacity nominations remain the same between the current four PGA configurations and the proposed two PGA configuration.[378]

352. The Department proposed that MERC reduce its Administrative and General expense by $11,422 to account for legal cost savings related to MERC's PGA consolidation proposal.[379] MERC accepted that recommendation.[380]

353. MERC proposed that consolidation of the PGA rates go into effect on July 1 after the final rates from this proceeding are imposed, and that consolidation of the true-up factors be effective with the first Annual Automatic Adjustment and True-Up filings made on September 1 after final rates go into effect.[381]

354. The Department concluded that the Company's proposal to consolidate its commodity cost recovery into two PGAs, Consolidated and Northern, is reasonable.[382]

355. The rate impacts related to PGA consolidation range from an increase of 0.13 percent to 5.98 percent, and a decrease of 6.43 percent, as shown in the table below.[383]

[375] Ex. 19 at 5-6 (C. Cloninger Direct).
[376] Ex. 41 at 48 (S. DeMerritt Direct).
[377] Hearing Transcript Vol. 1 at 38 (D. Kult); Ex. 41 at 50 and Schedule (SSD-24) (S. DeMerritt Direct).
[378] Ex. 41 at 50 (S. DeMerritt Direct).
[379] Ex. 112 at 23-24 (M. St. Pierre Direct).
[380] Ex. 41 at 13 (S. DeMerritt Direct).
[381] Ex. 72 at 19 (S. Gillespie Direct); Hearing Transcript Vol. 3 at 201-203 (G. Walters).
[382] Ex. 121 at 68-69 (A. Heinen Direct).
[383] Ex. 123 at 3 (Table AR-1 (DOC Information Request No. 793 (AJH-AR-1)) (A. Heinen Additional Rebuttal).

Table AR-1: Rate Impacts Related to PGA Consolidation (%)	
PGA System	Percentage Change
PNG-Northern	0.13%
PNG-Viking	0.46%
PNG-Great Lakes	5.98%
NMU-Northern	5.29%
NMU-All Other Pipelines	(6.43)%

356. Approximately one of eight MERC firm and interruptible customers will experience rate increases of approximately five percent as a result of the Company's proposed PGA consolidation plan. Approximately eleven percent of MERC's firm and interruptible customers will experience a rate decrease of approximately six percent.[384]

357. The average customer on the NMU-GLGT Lakes will pay an additional $5.34 per month during January and the average customer on NMU-NNG will pay an additional $5.35 during January as a result of the Company's proposed PGA consolidation.[385]

1. Consolidation Phase-In.

358. MERC and the Department have resolved all issues relating to the PGA consolidation, with the exception of the period of time to phase in the rate impacts. The Department initially recommended that the Commission require the Company to implement its rate changes for certain customers (customers served by the NMU-PGA and the PNG-GLGT PGA) over a three-year period to mitigate what it considers to be significant rate impacts and bring the price impacts more in line with historical monthly price variations.[386] In additional rebuttal testimony, the Department recommended that all of the rates, not just those for certain customers, be phased in over a three-year period.[387]

359. The Department recommends a phase-in over three years supported by a reasoned statistical analysis.[388]

360. MERC argued that a three-year phase-in of the PGA consolidation is unnecessary. It argued that implementing the full increase at one time will not have a significant impact on rates. MERC argued that a more appropriate indication of the

[384] Ex. 123 at 4-5 (Tables AR-2 and AR-3) (A. Heinen Additional Rebuttal).
[385] Ex. 123 at 6-7 (A. Heinen Additional Rebuttal).
[386] Ex. 121 at 62-63, 68-69 (A. Heinen Direct).
[387] Ex. 123 at 7 (A. Heinen Additional Rebuttal).
[388] *See* Department Initial Brief at 57.

estimated customer impact of immediate PGA consolidation is the change in average monthly customer costs, in dollars per month, for the average residential customer. The table below shows MERC's estimated impact of immediate PGA consolidation, on a dollar per month basis, for the average residential customer, using the updated gas costs submitted on June 15, 2011.[389]

Rate Impacts Related to PGA Consolidation ($)	
PGA System	**Average Dollar per Month Change**
PNG-Northern	$0.06
PNG-Viking	$0.19
PNG-Great Lakes	$2.41
NMU-Northern	$2.41
NMU-All Other Pipelines	($2.93)

361. MERC relied on the average monthly change to conclude that the impact of PGA consolidation is well within the range of monthly PGA rate changes routinely approved by the Commission. As shown in the table above, the impact for the average residential customer ranges between a decrease of $2.93 per month to an increase of $2.41 per month. MERC did not believe that immediate implementation would cause significant bill impacts or rate shock. In addition, MERC argued that a three-year phase-in of the PGA consolidation would be administratively difficult.[390]

362. DOC witness Mr. Adam Heinen determined the statistical significance of the rate impacts by evaluating historical PGA price information for each of MERC's PGA systems over the period from July 1999 to February 2011, and then finding the appropriate average monthly price changes and standard deviation of these price changes. Mr. Heinen used the average price and accompanying standard deviations to create a benchmark set of numbers from which it can be determined whether price changes may be considered "significant" to the average customer.[391] Mr. Heinen concluded that in terms of MERC's PGA consolidation, the rate impacts for PNG-Great Lakes, NMU-Northern, and NMU-All Other Pipeline customers represent "atypical events since the proposed rate impacts are more than two standard deviations away from the long-run average monthly PGA price changes."[392]

[389] Ex. 74 at 3, Table 1 (S. Gillespie Sur-Surrebuttal); *see also* Ex. 73 at 6, Table 2 and Schedule (SLG-2) (S. Gillespie Rebuttal) (showing March 31, 2011, cost of gas).
[390] Ex. 73 at 7 (S. Gillespie Rebuttal).
[391] Ex. 121 at 62-63 (Heinen Direct).
[392] *Id.* at 63.

363. Based on his statistical analysis, Mr. Heinen concluded that the Company's PGA consolidation proposal would result in rate shock, particularly since MERC's PGA consolidation would affect the larger portion of the ratepayer's bill (*i.e.*, gas costs).[393] Therefore, the Department recommended that the Commission require MERC to phase in any rate changes for these customers over a three-year period so that the monthly rate impacts are lessened.[394]

364. MERC's initial proposal did not propose any gradual phase-in of rates. The Company argued that a rate phase-in would be administratively difficult and could cause unintended costs shifts between PGA systems.[395]

365. After MERC updated its gas cost projections in rebuttal testimony, the Department reviewed its initial recommendation, and determined that the updated projections do not impact the original recommendations regarding the Company's proposed PGA consolidation; *i.e.,* the average percentage impact of MERC's PGA consolidation for PNG-GLGT and NMU-NNG are still more than two standard deviations above the average monthly price changes in Mr. Heinen's additional rebuttal testimony.[396] In fact, the negative impacts to these ratepayers have increased since MERC completed its initial analysis in response to the Department Information Requests.[397] Based on this information from MERC, Mr. Heinen projected that the average customer on PNG-GLGT would pay an additional $5.34 per month during January and the average customer on NMU-Northern would pay an additional $5.35 during January as a result of the Company's proposed consolidation and between $3.90 and $5.30 monthly during the other heating season months.[398]

366. The Department does not agree with MERC's conclusion that these updated monthly cost impacts of PGA consolidation are well within the range of monthly PGA rate changes routinely approved by the Commission, making a phase-in of the PGA consolidation unnecessary.[399] Mr. Heinen further concluded that it would be appropriate to phase in all of the rates over a three-year period rather than only PNG-GLGT, NMU-NNG, and NMU-All Other Pipeline customers.[400]

367. The ALJ finds that MERC has not met its burden to establish by a preponderance of the evidence that its proposed immediate consolidation is reasonable. The ALJ finds that the three-year phase-in of the PGA Consolidation proposed by the Department is reasonable.

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[393] *Id.* at 63-64.
[394] *Id.* at 64.
[395] MERC Ex. 73 at 7-9 (Gillespie Rebuttal).
[396] *See* Ex. 123 at 5-6, and Table Ar-3 (Heinen Rebuttal).
[397] *Id.* at 6.
[398] *Id.* at 7. MERC's calculations of the monthly bill impact for the average customer are based on averaging costs for 12 months rather than calculating the impact during the cooler months when more gas is used, as the DOC did. *See e.g.,* MERC Ex. 74 at 3 (Gillespie Sur-Surrebuttal).
[399] DOC Initial Brief at 58-59.
[400] *See Id.* at 7; and MERC Ex. 73 at 8-9 (Gillespie Rebuttal).

VIII. REVENUE DECOUPLING – PRIMARY DECOUPLING PROPOSAL, REVENUE DECOUPLING MECHANISM (RDM)

A. Overview

368. Revenue decoupling is a regulatory tool designed to separate a utility's revenue from changes in energy sales, with the purpose of reducing "a utility's disincentive to promote energy efficiency."[401]

369. One barrier to promoting energy efficiency is the "throughput incentive" that electric and gas utilities have under traditional ratemaking. The throughput incentive is the incentive to sell more gas because as sales volumes increase, the utility's revenues increase, and the closer the utility comes to obtaining or exceeding its Commissioner-approved revenue requirement. This is true for a natural gas distribution utility like MERC even though it does not make a profit on sales of the gas commodity, but instead passes such commodity costs dollar for dollar through to the customers.

370. MERC's interest in selling more natural gas arises because its rates to recover the fixed costs of providing natural gas delivery service have been structured with volumetric components, *e.g.*, $/Therm. Use of rates with volumetric components to recover the fixed costs of MERC's delivery infrastructure and service means that MERC has an economic interest in its customers' consumption levels of natural gas. When customers use less natural gas, MERC collects less revenue through the volumetric components of its rates that were set at a level to recover its fixed costs of providing natural gas delivery service.

371. Decoupling removes throughput incentives by providing stable revenue for utilities regardless of sales volume. Depending on the program design, decoupling mechanisms can sever the link between customer sales volumes and fixed cost recovery for the utility's delivery infrastructure.

372. MERC proposes a full RDM to be implemented in the rates charged to ratepayers in MERC's residential and Small C&I rate classes.[402]

373. MERC's proposed RDM will separate (or decouple) MERC's revenues from the volume of gas that it sells, thereby removing the financial disincentive to promote energy efficiency and allowing MERC the opportunity to earn its Commission-approved revenue requirement.[403]

374. The RDM is a symmetrical true-up mechanism that will adjust, on a per customer basis, for sales volumes that are above or below the approved sales level for the rate group that is used to determine the volumetric distribution charges approved by the Commission. The symmetrical design of the RDM will result in a bill charge if the

[401] Minn. Stat. § 216B.2412, sub. 1 (2010).
[402] Ex. 84 at 5, 10 (V. Grace Direct).
[403] Ex. 84 at 5 (V. Grace Direct)

rate group's usage is below the approved sales level and a bill credit if the rate group's usage is above the approved sales level.[404]

375. The true-up decreases or increases rates charged to classes of customers if their collective usage during a given time period deviates from a set base amount. The mechanism is considered to be a full decoupling mechanism because the true-up amount is based on deviations from forecasted revenue that occur for any reason, including weather.[405]

376. MERC provided a proposed tariff detailing the parameters of the decoupling pilot program. MERC proposes that the program run for three full calendar years, plus any partial calendar year in which the RDM becomes effective. The Company may request approval from the Commission to extend the RDM beyond the three-year pilot period.[406]

377. MERC proposes to file annual reports to the Commission that specify the RDM adjustment to be applied to each rate class for the billing period. The reports will also include an evaluation plan with information required by the Commission's Revenue Decoupling Criteria and Standards in Docket No. E, G-999/CI-08-132. MERC proposes to file its first reports on March 31 of the calendar year following the Commission's approval for the RDM, and on March 31 of each succeeding year until the RDM terminates.[407]

B. Decoupling Legislation and MERC's Energy Conservation Goals

1. The Next Generation Energy Act.

378. The Next Generation Energy Act (NGEA) of 2007 increased Minnesota's commitment to energy conservation. With respect to energy conservation the NGEA, codified in Minn. Stat. § 216B.2401, specifically states:

> Sec. 4. ENERGY CONSERVATION POLICY GOAL. It is the energy policy goal of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design, and indirectly through codes and appliance standards, programs designed to transform the market or change customer behavior, energy savings resulting from efficiency improvements to the utility infrastructure

[404] Ex. 84 5 at (V. Grace Direct).
[405] Ex. 126 at 2-3 (C. Davis Direct).
[406] Ex. 84 at Schedule 3 (VHG-1) (V. Grace Direct); *see also* Minn. Stat. § 216B.2412, subd. 3 ("A pilot program may not exceed three years in length. Any extension beyond three years can only be approved in a general rate case, unless that decoupling program was previously approved as part of a general rate case.").
[407] Ex. 84 at Schedule 3 (VHG-1) (V. Grace Direct); *cf.* Hearing Transcript Vol. 2 at 86 (MERC witness V. Grace stating annual reports would be submitted on March 31 of each year following Commission approval of RDM). The day on which the reports are submitted is immaterial to MERC.

and system, and other efforts to promote energy efficiency and energy conservation.

As shown in the language above, the NGEA established an aggressive statewide energy savings goal of 1.5 percent of annual retail electric and gas sales through energy efficiency.

379. The NGEA originally included an energy conservation goal of 1.5 percent of annual retail electric and gas sales energy efficiency.[408] In 2009, however, the Minnesota Legislature enacted the Omnibus Energy Bill (Chapter 110), which included a provision allowing natural gas utilities a ramp-up period for energy savings in their 2010-2012 Triennial CIP Plans. Specifically, the bill established an energy conservation goal for natural gas facilities of 0.75 percent annual energy savings until 2012, and 1.0 percent annual savings thereafter.[409]

380. In its Final Triennial CIP Plan for 2010-2012, MERC-PNG set a three-year average annual energy savings goal of 0.92 percent.[410] In the Final Triennial CIP Plan for 2010-2012, MERC-NMU proposed a three-year average annual energy savings goal of 0.78 percent.[411] MERC's current energy savings goals included in their CIP plans therefore exceed the conservation requirements of Minnesota law.

2. The Decoupling Statute.

381. The NGEA identified two direct means of achieving statewide energy savings – through energy efficiency and rate design. Decoupling is one example of a rate design mechanism expressly provided for in the NGEA. The NGEA allows utilities to implement pilot projects to try "decoupling" the utility's revenue from changes in energy sales to encourage the utility to promote more conservation.[412]

382. As part of the NGEA, the legislature enacted Minn. Stat. § 216B.2412 (the decoupling statute), which defined decoupling as a "regulatory tool designed to separate a utility's revenue from changes in energy sales." Section 216B.2412 specifically directed the Commission to establish criteria and standards by which decoupling could be adopted by the state's regulated utilities.[413]

383. The legislation also required the Commission to allow one or more rate-regulated utilities to participate in a pilot program to "assess the merits of a rate-decoupling strategy to promote energy and conservation."[414]

[408] Minn. Stat. § 216B.2401
[409] *See* Minnesota Session Laws 2009, Chapter 110, subd. 5b.
[410] See Docket No. G011/CIP-09-800, Final Triennial CIP , filed May 7, 2009.
[411] See Docket No. G011/CIP-09-803, Final Triennial CIP, filed May 7, 2009.
[412] Minn. Stat. § 216B.2412; Ex. 126 at 4-5 (C. Davis Direct).
[413] Minn. Stat. § 216B.2412, subd. 1.
[414] Minn. Stat. § 216B.2412, subd. 3.

384. Based on the language of Minn. Stat. § 216B.2412, any decoupling mechanism must meet basic policy requirements. Specifically, a decoupling mechanism must:

- reduce a utility's disincentive to promote energy efficiency;
- be designed to determine whether a rate-decoupling strategy achieves energy savings; and
- not adversely impact ratepayers.[415]

385. To fulfill its obligation to develop criteria and standards for decoupling, the Commission sought the advice of the Regulatory Assistance Project (RAP), a non-profit group of former utility regulators. On June 30, 2008, RAP issued its Report on Revenue Decoupling, Standards and Criteria (Decoupling Report) to the Commission.[416]

386. The Decoupling Report discussed definitions and descriptions of the various forms of decoupling available (full, partial and limited), issues associated with decoupling, alternatives to decoupling, decoupling programs in other states, and the mechanics of decoupling. The Report contains recommendations on the criteria and standards by which the Commission could design and evaluate a decoupling proposal, and a "straw proposal" for a decoupling mechanism for a natural gas utility.[417]

387. The Commission issued its Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling on June 19, 2009, Docket No. E, G-99/CI-08-132. In its Order, the Commission adopted a number of Criteria and Standards to be applied to decoupling proposals. Specifically, the Commission's Order requires that all utility decoupling pilot proposals provide the following information in the initial filing: (1) Purpose; (2) Form; (3) Cost of Capital; (4) Classes Included; (5) Mechanics; (6) Service Quality; (7) Review; and (8) Pilot Implementation.[418] MERC has provided all the information required by the Commission Order in its initial filing and the testimony of Valerie Grace.

388. As part of that Order, the Commission asked utilities to file a non-binding notice of intent whether they would file a proposed decoupling pilot program by June 1, 2010.

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[415] Ex. 126 at 6-7 (C. Davis Direct).

[416] *ITMO a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Decoupling Report to the PUC, Docket No. E,G999/CI-08-132 (July 15, 2008).

[417] *ITMO a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Decoupling Report to the PUC at 32, Docket No. E,G999/CI-08-132 (July 15, 2008).

[418] *See ITMO a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, ORDER ESTABLISHING CRITERIA AND STANDARDS TO BE UTILIZED IN PILOT PROPOSALS FOR REVENUE DECOUPLING at 7-9, Docket No. E,G999/CI-08-132 (July 19, 2009).

389. On May 27, 2010, MERC filed with the Commission its notice of intent to file a decoupling pilot program as part of this general rate case in that docket.

3. CenterPoint Energy.

390. On January 11, 2010, the Commission approved a partial decoupling pilot program for CenterPoint Energy that was stipulated to by various parties in CenterPoint's general rate case.[419]

391. CenterPoint's approved decoupling program was a partial decoupling program (as opposed to MERC's full decoupling mechanism) that included an inverted block rate design.[420] The difference between full and partial decoupling mechanisms is discussed below.

C. Full Versus Partial Decoupling Mechanisms

392. As stated, MERC's proposed RDM is a full decoupling mechanism. Full decoupling means the mechanism will compute an adjustment for all changes in usage per customer above or below the sales level approved in this rate case proceeding. Such usage changes could arise from customer energy efficiency and conservation efforts, increased customer usage, weather variations, or for other various reasons.[421]

393. A partial decoupling mechanism is typically one that would compute adjustments for either conservation or weather-related changes in customers' usage, but not both.[422]

394. For example, if residential customers used five percent less than the baseline distribution amount, and half of that decrease was related to warmer-than-normal weather conditions, then under a full decoupling mechanism the utility would surcharge these ratepayers for the full five percent. By contrast, if the utility has a partial decoupling mechanism that removes weather effects from the true-up, that same utility would only recover one-half of the five percent under-recovery, or 2.5 percent of the reduction from the base.[423]

395. Conversely, if residential customers used five percent more than the baseline distribution amount and half of the increase was due to colder-than-normal conditions, then under a full decoupling mechanism the utility would decrease rates to reflect the full five percent. Under the partial decoupling the utility would decrease rates to reflect only one-half of the five percent over-recovery.[424]

[419] *ITMO the Application of CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-08-1075 (January 11, 2010).
[420] Ex. 84 at 7-8 (V. Grace Direct).
[421] Ex. 84 at 7 (V. Grace Direct).
[422] Ex. 84 at 7 (V. Grace Direct).
[423] Ex. 126 at 3 (C. Davis Direct).
[424] Ex. 126 at 3 (C. Davis Direct).

396. Minn. Stat. § 216B.2412, subd. 1, directs the Commission to consider energy efficiency and weather among other factors when designing the criteria and standards for decoupling. A full decoupling mechanism, which would be symmetrical, would allow the Commission to assess the effects of both energy efficiency and weather that varies from the normal weather assumed for ratemaking purposes.[425]

397. A partial decoupling mechanism that would compute adjustments only for energy efficiency and conservation related usage changes would be asymmetrical and not provide as much value as a full decoupling mechanism that considers other factors. A partial decoupling mechanism that considers only reduced usage would not fully align the interests of MERC and its customers, because it would not provide bill credits to customers if their usage is greater than the usage level approved by the Commission because of weather or other factors.[426]

398. A partial decoupling mechanism is also more complicated to compute, potentially administratively burdensome, and may cause disputes about the appropriate quantification of usage changes and affected sales volumes.[427]

399. A full decoupling mechanism, such as MERC's proposed RDM, is simpler to compute, will align the interests of MERC and its customers, and minimize debates related to the quantification of sales levels or changes in usage.[428]

400. The proposed RDM will fully decouple MERC's volumetric sales levels from its distribution revenues, thereby removing the disincentive to promote energy efficiency and allowing MERC the opportunity to earn its Commission approved revenue requirement.[429]

401. MERC's customers will benefit from any company sponsored energy efficiency programs and from bill credits that would arise from the symmetrical operation of the mechanism.[430]

D. Operation of the RDM

402. MERC's proposed decoupling program is modeled after those approved by the Illinois Commerce Commission for the Peoples Gas and Coke Company and North Shore Gas Company, both Integrys subsidiaries.[431]

403. The proposed RDM calculates the difference between (1) baseline annual distribution revenues per customer for the rate group approved in the most recent rate case proceeding, and (2) actual annual distribution revenues per customer for the rate group. This difference will be multiplied by the average number of customers that were

[425] Ex. 84 at 7 (V. Grace Direct).
[426] Ex. 84 at 7-8 (V. Grace Direct).
[427] Ex. 84 at 8 (V. Grace Direct).
[428] Ex. 84 at 8 (V. Grace Direct).
[429] Ex. 84 at 7-8 (V. Grace Direct)
[430] Ex. 84 at 8 (V. Grace Direct).
[431] Ex. 96 at 14 and Schedule (VCC-8) (V. Chavez Direct).

used to establish charges in the most recent general rate case proceeding to determine the dollar amount that will be collected from, or refunded to, customers. The amount will be recovered or refunded on a per therm basis over a twelve-month period.[432]

404. As the Department explains, MERC has a base non-gas margin without revenue from the CCRC. This base revenue, called the RDM revenue, is the amount MERC proposes to use to determine the true-up responsibility (rate increase or decrease) for ratepayers in each affected class of customers.[433]

405. MERC's base amount is determined by calculating the annual rate class RDM revenue per customer (RDM True-up Factor). The RDM True-up Factor is based on test year rate class RDM revenue divided by the number of test year rate class customers, which are both calculated in the Company's sales forecasting analysis.[434]

406. The Schedules attached to MERC witness Valerie Grace's direct testimony reflect MERC's proposed methodology for establishing the baseline for each rate group, assuming the charges proposed in this proceeding (VHG-1 Schedule 1),[435] and the symmetrical operation of the RDM under two different scenarios assuming a change in distribution revenues of three percent from the baseline of each rate group (VHG-1, Schedule 2).

407. The proposed tariff language for the RDM is also attached to Valerie Grace's direct testimony.[436]

E. Analysis of Statutory Requirements

408. As set forth above, to comply with the decoupling statute, Minn. Stat. § 216B.2412, a proposed decoupling mechanism must 1) reduce a utility's disincentive to promote energy efficiency; 2) be designed to determine whether a rate-decoupling strategy achieves energy savings; and 3) not adversely impact ratepayers.

1. RDM Must Reduce a Utility's Disincentive to Promote Energy Efficiency.

409. MERC's full decoupling proposal meets the first criterion that requires a proposed decoupling mechanism to reduce a utility's disincentive to promote energy efficiency. Under MERC's proposal, the Company will not make more money through additional sales.

410. The Department agreed that the first statutory criterion is met.[437]

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[432] Ex. 84 at 11-12 (V. Grace Direct).
[433] Ex. 126 at 3 (C. Davis Direct).
[434] Ex. 126 at 3-4 (C. Davis Direct).
[435] *See* also baseline calculation updated to reflect actual customer counts submitted with S. DeMerritt Sur-Surrebuttal, Ex. 87 at Schedule (VHG-1) Schedule 1 (V. Grace Sur-Surrebuttal).
[436] Ex. 84 at Schedule (VHG-1) and Schedule 3 (V. Grace Direct).
[437] Ex. 126 at 9 (C. Davis Direct).

2. RDM Must Be Designed to Determine Whether a Rate-Decoupling Strategy Achieves Energy Savings.

411. Regarding the second criterion, MERC proposed an annual evaluation plan for its pilot program.[438]

412. The Department determined that the evaluation plan met the Commission's Revenue Decoupling Criteria and Standards in Docket No. E, G-999/CI-08-132, but that the plan was inadequate to determine whether the rate decoupling strategy achieved energy savings. The Department recommended that MERC commit to an evaluation plan similar to the one approved for CenterPoint.[439]

413. The OAG and IWLA/MCEA witnesses made similar recommendations.[440]

414. In rebuttal testimony, MERC agreed to submit an evaluation plan similar to that approved for CenterPoint. A copy of the proposed evaluation plan is attached to the rebuttal testimony of MERC witness Valerie Grace.[441]

3. RDM Must Not Adversely Impact Ratepayers.

415. Regarding the third criterion that a decoupling proposal should not adversely impact ratepayers, in its direct testimony the Department determined that the proposal could not be implemented without adversely impacting ratepayers because the proposal placed all the weather risk on the ratepayers and no weather risk on the Company.[442] In subsequent testimony, the Department made a number of suggestions to mitigate the risk to ratepayers and MERC agreed to the Department's suggested improvements.

416. At the evidentiary hearing, Department witness Christopher Davis recommended the Commission approve MERC's full decoupling proposal with five conditions:

1) the imposition of a ten percent cap on revenues generated through the application of the RDM;

2) the requirement that MERC use an evaluation plan similar to that used by CenterPoint in its decoupling program;

3) the requirement that MERC calculate the RDM adjustment factors using the customer counts and distribution revenues proposed by Department witness Adam Heinen in his

[438] Ex. 84 at 14 (V. Grace Direct).
[439] Ex. 126 at 10-13 (C. Davis Direct).
[440] Ex. 91 at 8 (R. Hornby Direct); Ex. 126 at 12-13 (C. Davis Direct).
[441] Ex. 85 at 11 and Schedule (VHG-3) (V. Grace Rebuttal).
[442] Ex. 126 at 13 (C. Davis Direct).

additional rebuttal testimony, subject to the results of the audit of MERC's billing system;

4) clarification that the Commission may modify the rates in the pilot if warranted by unexpected circumstances; and

5) that the decoupling proposal not be extended to MERC's large customers.

Each of these recommendations will be discussed below.

a. Ten Percent Cap.

417. The Department recommended that a ten percent cap be placed on the amount of revenues that MERC under or over collects through its RDM on non-gas margin rates, excluding CCRC rates.[443]

418. In rebuttal testimony, MERC agreed that a symmetrical cap of 10 percent of non-gas margin rates, excluding CCRC rates, was acceptable, provided the appropriate parameters are used to determine the RDM adjustments.[444]

419. With the ten percent cap in place, assuming average annual use of 85 Mcf, the revenue decoupling adjustment for a residential customer will be approximately $21 [more] per year.[445]

b. Evaluation Plan.

420. As discussed above, MERC has agreed to use a comprehensive evaluation plan similar to CenterPoint's as recommended by the Department.

c. Customer Counts and Distribution Revenues.

421. The Department recommended that MERC calculate the RDM adjustment factors using the customer counts and distribution revenues proposed by witness Adam Heinen.

422. As discussed above under sales forecast, MERC and the Department have agreed upon the suitability of the sales and revenue forecasts submitted with the sur-surrebuttal testimony of Seth DeMerritt.

423. Further, at the evidentiary hearing, MERC witness Valerie Grace acknowledged that if a change in the sales or customer forecast arises from the audit of

[443] Ex. 126 at 15 (C. Davis Direct).
[444] Ex. 85 at 11 and Schedule (VHG-2) (V. Grace Rebuttal).
[445] Ex. 126 at 15 (C. Davis Direct).

MERC's billing system and distribution rates are affected, the resulting RDM baseline would need to be adjusted accordingly.[446]

d. Commission's Ability to Modify Rates.

424. The Department recommended that a condition be included in MERC's decoupling proposal to clarify that the Commission may modify the rates in the pilot if warranted by unexpected circumstances.

425. MERC acknowledged that the Commission has the authority to investigate the reasonableness of a utility's rates and to order the utility to initiate a rate proceeding if it is unable to resolve a complaint regarding reasonableness.[447]

426. In addition, as set forth in the Commission's Standards, all utility pilot proposals shall be reviewed yearly. If the Commission determines that the pilot is harming ratepayers or failing to meet objectives, the Commission may suspend the pilot at any time or recommend modifications thereto.[448]

e. Other Customer Classes.

427. The Department recommended that the RDM not be extended to MERC's large customers. The Department agreed with MERC that the RDM should apply only to two rates classes.

428. MERC proposed that the RDM apply to two different rate groups – General Service – Residential (MERC NNG and MERC Consolidated) and General Service – Small C&I. The RDM will not apply to any other rate class, i.e., the Large C&I customers under the General Service rate schedule (those that use more than 1,500 therms of gas per year) or any other large customer class.[449]

429. RDM adjustments will be determined separately for the two different rate groups – General Service Residential and General Service - Small C&I.[450]

430. This proposal satisfies the Commission's requirement that a revenue decoupling pilot program be implemented in more than one customer class. The RDM was not proposed for MERC's remaining rate classes, which are more heterogeneous with respect to usage and uniquely affected by economic conditions in comparison to

[446] Hearing Transcript Vol. 2 at 31 (V. Grace).
[447] *See* Minn. Stat. § 216B.17; Ex. 85 at 19 (V. Grace Rebuttal).
[448] *See ITMO a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, ORDER ESTABLISHING CRITERIA AND STANDARDS TO BE UTILIZED IN PILOT PROPOSALS FOR REVENUE DECOUPLING at 7-9, Docket No. E,G999/CI-08-132 (July 19, 2009).
[449] Ex. 84 at 10 (V. Grace Direct); Hearing Transcript Vol. 2 at 80-82 (V. Grace).
[450] Ex. 84 at 10 (V. Grace Direct).

the General - Residential and Small C&I classes proposed to be included in the program.[451]

431. The remaining rate classes are also subject to interruption under certain terms in MERC's tariff.[452]

432. In addition, the large and industrial customers excluded from MERC's RDM proposal often have great price sensitivity, which could lead to the loss of customers from MERC's system through bypass or fuel switching.[453]

433. In direct testimony, the OAG proposed that if the Commission approves MERC's revenue decoupling, the Commission should apply the proposed RDM to all customer classes.[454]

434. In rebuttal testimony, Department witness Christopher Davis supported the OAG's position that the RDM should apply to all customer classes, but at the evidentiary hearing he declined to support that position.[455]

435. Witness Davis explained that even though he agreed with the OAG that the decoupling proposal should include MERC's large customer classes to remove the utility's disincentive to implement energy conservation programs for those customers, he ultimately could not recommend that the larger classes be included in MERC's proposal because of the structure of the rate design in those classes. Many large customer class rates are not designed to include the same throughput incentive as smaller customer classes. In other words, the rates for large customers may already be decoupled. He determined that the Department needed to fully and systematically analyze the effects of decoupling on large customer classes before it could support the application of the RDM to those classes.[456]

436. In MERC's instance, the rates for its SLV and flex rate customers are essentially straight variable rates, meaning those customers are charged a substantial customer charge, while the volumetric rates remain low, essentially covering only marginal costs. Because the customer charges are set to recover the fixed customer costs in those large classes, the throughput incentive for MERC to sell increased quantities to those customers is less than for the General Service - Residential and Small C&I classes.[457] In other words, to a large extent, the rate design for MERC's larger customers is already decoupled.

437. The rationale for excluding certain classes from the application of the RDM was also supported by the Commission's January 11, 2010, Order in the CenterPoint proceeding, Docket No. G-008/GR-08-1075. The Commission found, as

[451] Ex. 84 at 10-11 (V. Grace Direct).
[452] Ex. 84 at 10-11 (V. Grace Direct).
[453] Hearing Transcript Vol. 2 at 31, 60. (V. Grace).
[454] Ex. 96 at 61 (V. Chavez Direct).
[455] Ex. 127 at 4 (C. Davis Rebuttal); Hearing Transcript Vol. 3 at 47-49 (C. Davis).
[456] Hearing Transcript Vol. 3 at 47-48 (C. Davis).
[457] Hearing Transcript Vol. 3 at 66-67, 69 (C. Davis).

did the Administrative Law Judge, that the exclusion of certain larger customer classes was reasonable because the usage in those classes was "more closely tied to general economic conditions than the firm sales classes."[458]

438. There could be adverse impacts on customers if the RDM is applied to the classes MERC proposes to exclude. The excluded classes are subject to interruption and some excluded classes include a small number of large usage, heterogeneous customers. Accordingly, unlike the included classes, if one large customer's usage were to decline based upon economic or customer-specific conditions, or if one or more customer's usage is interrupted, those remaining customers could be assessed a surcharge, which would be substantial if the class includes only a small number of customers.[459]

439. The RDM adjustment will be computed specifically and separately for each included rate group (comprised of similar rate classes), and would be based upon the Commission's approved revenue requirement for each specific rate class. Accordingly, RDM adjustments determined for each included rate class would not be impacted by, nor have any effect on, any other rate class.[460]

440. Importantly, Witness Davis concluded that MERC has committed to, and is thus far achieving, energy savings that surpass historical levels.[461]

441. The table below shows MERC's (MERC-PNG and MERC-NMU combined) 2007-2010 actual energy savings and approved goals for 2011-2012 in terms of energy savings and percent of retail sales.[462]

MERC (NMU and PNG)	**Energy Savings (MCF)**	**Energy Savings (% of Retail Sales)**
2007	141,655	0.26%
2008	64,517	0.12%
2009	133,569	0.24%
2010	419,455	0.80%
2011	491,379	0.90%
2012	564,942	1.03%

[458] Ex. 85 at 8 (V. Grace Rebuttal).
[459] Ex. 85 at 9 (V. Grace Rebuttal).
[460] Ex. 85 at 9-10 (V. Grace Rebuttal).
[461] Ex. 127 at 4 (C. Davis Rebuttal).
[462] Ex. 126 at 8 (C. Davis Direct); Ex. 127 at 4 (C. Davis Rebuttal).

442. Department Witness Davis concluded that the information above shows that MERC has made impressive steps toward reaching the 1.5 percent energy savings goal. The goal of achieving energy savings equal to 1.03 percent of retail sales is particularly impressive given that MERC's combined energy savings equaled only 0.26 percent in 2007.[463]

443. Based on its increase in historical energy savings, approved goals, and commitment to submit additional projects following approval of a decoupling mechanism, MERC has demonstrated enough commitment to increasing energy savings to warrant the Commission's approval of a pilot decoupling project.[464]

F. RDM and Price Signal Distortion

444. The Department determined that approval of an RDM would have little impact on a customer's price signal. The Department considered the following scenario: MERC experiences warm weather equivalent to once in 20 years; the Commission approves a ten percent cap on distribution revenues; the $2.23 per MCF in distribution revenues requested by MERC in this proceeding; and base cost of gas of $6.10 per MCF, so that the total cost is $8.33 per MCF. In this scenario, the customer's cost per MCF would increase by 22 cents ($2.23 x 10 percent).[465]

445. The Department concluded that MERC's RDM, with the ten percent cap, would only increase a residential customer's cost per MCF by 3 percent ($0.21/$6.31) under the most extreme circumstances. Commission approval of an RDM for MERC would have little impact on a customer's price signal and customers will still have a significant incentive to save energy.[466]

G. Annual Versus Monthly Adjustments

446. In direct testimony, the Department also recommended that the RDM adjustments be calculated and implemented on a monthly basis, not annually, with a one-month lag.[467]

447. MERC disagreed that a monthly RDM adjustment is necessary, or that a one-month lag is practical. The current pilot decoupling mechanisms for The Peoples Natural Gas Light and Coke Company and North Shore Gas Company, MERC's affiliate Illinois utilities, are real-time, with a two-month lag, and were initially established as monthly mechanisms for the same reasons expressed by Department witness Chris Davis. After three years of administering those monthly mechanisms, and from a practical standpoint, the Illinois utilities learned that monthly adjustment results could

[463] Ex. 126 at 8 (C. Davis Direct).
[464] Ex. 126 at 9 (C. Davis Direct).
[465] Ex. 127 at 6 (C. Davis Rebuttal); Hearing Transcript Vol. 3 at 44 (C. Davis).
[466] Ex. 127 at 6 (C. Davis Rebuttal); Hearing Transcript Vol. 3 at 57-58 (C. Davis).
[467] Ex. 126 at 17-18 (C. Davis Direct).

vary in type (credit or charge) and magnitude from month-to-month for a variety of reasons, and they have proposed changing to annual adjustments.[468]

448. While a monthly adjustment would effectively decouple revenue from sales, as would an annual adjustment, it does not smooth-out and streamline adjustments as an annual adjustment would. Monthly adjustments also cause other concerns such as timing and implementation of the adjustment. Annual adjustments provide rate simplicity and rate stability for both customers and the utilities.[469]

449. The use of a monthly mechanism will eventually result in the same amount recovered or refunded through an annual mechanism, but with more work required to determine, file and review monthly adjustments and more varying adjustments on customers' bills.[470]

450. At the evidentiary hearing, Department witness Christopher Davis stated that he no longer supported monthly adjustments. Instead, he supported either annual or bimonthly adjustments.[471]

H. RCN and RCC.

451. The Department recommended changes to the source of data used to calculate MERC's RDM because of concern that Department witness Adam J. Heinen raised regarding with the way the Company counted customers. In response to this concern, the Department proposed two modifications that would change the source of the data for the calculation of the decoupling mechanism, but not the calculation itself. The modifications can be used to calculate MERC's RDM regardless of whether the Commission adopts the MERC sales forecast proposed in its initial rate case filing, which the Administrative Law Judge recommends, or instead adopts the forecast submitted by MERC in its surrebuttal testimony.[472]

452. Specifically, Department witness Mr. Christopher Davis' first modification would use class revenue requirements after removing the fixed charge portion and CCRC revenues from the final revenue apportioned to the customer class instead of using Ms. Grace's definition of rate case margin (RCM). Second, instead of using Ms. Grace's definition of Rate Case Customers (RCC), Mr. Davis proposed using the actual 2011 customer count (instead of a forecasted customer count). The Department's proposed modification differed only by changing the source of the data from test year to actual 2011 counts, not changing the way to calculate the RDM Adjustment Factor.[473]

453. To reflect this change in the definition of RCM, the Department recommended changing the definitions of the RCM and RCC. The Department

[468] Ex. 85 at 12 (V. Grace Rebuttal).
[469] Ex. 85 at 12-14 (V. Grace Rebuttal).
[470] Ex. 85 at 12 (V. Grace Rebuttal); Ex. 129 (Department's calculation of difference in administrative costs of annual versus monthly RDM adjustments).
[471] Hearing Transcript Vol. 3 at 65-66 (C. Davis).
[472] Ex. 126 at 18-19 (Davis Direct).
[473] Ex. 126 at 19 (Davis Direct).

proposed changing the definition of the RCM so that the distribution revenues are those assigned to the rate class rather than revenue calculated based on forecasting. The Department also proposed changing the definition of RCC to the actual 2011 customer count after a full audit of MERC's billing system.[474]

454. MERC has agreed to, and is currently in the process of conducting a full billing system audit. The data existing after this full audit can be used to calculate MERC's RDM, whether the Commission approves MERC's original forecast or the later one.[475]

I. Conclusion.

455. MERC's proposed RDM, a full decoupling mechanism, complies with Minnesota law and previous Commission Orders and is based on sound ratemaking principles. The RDM should be computed annually and applied only to the Residential and Small C&I rate groups. The Commission should also impose a symmetrical ten percent cap on RDM revenues, and require MERC to submit an annual evaluation plan similar to the one used in CenterPoint's decoupling pilot.

456. With these conditions, the Administrative Law Judge recommends that the Commission approve MERC's proposed full revenue decoupling mechanism as a pilot program to run three full calendar years. The Commission should also require MERC to file annual reports to the Commission that specify the RDM adjustment to be applied to each rate class for the billing period and demonstrate annual progress toward achieving the 1.5 percent energy efficiency goal set forth in Minn. Stat. § 216B.241.

457. The IWLA and MCEA support implementation of this proposed full decoupling pilot program for MERC, and believe it will place MERC in a better position to embrace greater conservation achievements since decreased sales volumes will no longer bring a corresponding revenue reduction.[476]

IX. Alternative Decoupling Proposal – Straight Fixed Variable (SFV)

458. MERC presented a Straight Fixed Variable (SFV) rate design, or a variant thereof, or a flat monthly "Service Charge" as an alternative decoupling proposal.

459. A SFV rate would assign all fixed costs to fixed charges and all variable costs to variable charges. The result is that a utility's fixed charge is much higher than under current ratemaking procedures, and the variable charges are lower.[477]

460. About 92 percent of MERC's costs for its Residential rate group are fixed, and 90 percent of its costs for the Small Commercial rate group are fixed. The

[474] Ex. 126 at 19-20 (Davis Direct).
[475] *See* Tr. Vol. 1 at 103-104 (DeMerritt testimony).
[476] IWLA and MCEA Post-Hearing Brief at 2.
[477] Ex. 126 at 20 (C. Davis Direct).

proposed Service Charges would assign all fixed costs to flat fixed monthly charges.[478] For MERC's Residential and Small Commercial rate groups, the proposed monthly service charges are $24.25 and $29.60, respectively.[479]

461. The Department noted that the monthly service charges MERC proposed would be difficult to implement, and that even though the total bills charged to customers might be similar under either of MERC's SFV or RDM proposals, a fixed charge of $25 or $30, in addition to charges for other costs, would likely cause concern to customers.[480]

462. No party supported the use of the SFV over the use of MERC's RDM proposal.

X. OTHER COMMISSION REQUIREMENTS

463. In its September 14, 2009, Order in MERC's 2008 rate case, the Commission required MERC to retain documentation needed to substantiate the reasonableness of any charges for materials assessed in situations in which tampering has occurred and any new materials are needed for the reconnection of gas service.

464. MERC provided this information with the direct testimony of David Kult.[481]

465. The Department recommended that MERC continue to be required to track this information and retain documentation to substantiate the reasonableness of any materials assessed in situations where tampering occurred and any new materials needed to reconnect gas service.[482]

466. The ALJ finds that this request is not unreasonable.

XI. FILING REQUIREMENTS FOR TRAVEL, ENTERTAINMENT, AND OTHER EMPLOYEE EXPENSES

467. In 2010, Minn. Stat. § 216B.16 was amended to include subdivision 17, which specifies the filing requirements for travel, entertainment, and other employee expenses.[483]

468. In its initial filing, MERC provided the information required by Minn. Stat. § 216B.16, subd. 17, including the travel, entertainment, related expenses, and separately itemized expenses for MERC's board of directors and ten highest paid employees.[484]

469. Minn. Stat. § 216B.16, subd. 17(c), allows for the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, to be

[478] Ex. 84 at 17 (V. Grace Direct).
[479] Ex. 84 at 17 (V. Grace Direct).
[480] Ex. 126 at 21 (C. Davis Direct).
[481] Ex. 20 at Exhibit (DGK-5) (D. Kult Direct).
[482] Ex. 104 at 61 (B. Minder Direct); Ex. 105 at 18 (B. Minder Surrebuttal).
[483] Minnesota Laws, 2010, Chapter 328, Section 2.
[484] Ex. 41 at 55-59 (S. DeMerritt Direct); Vol. 3, Informational Requirements, Document 14 at 1.

treated as private data on individuals. Specifically, Minn. Stat. § 216B.16, subd. 17(c), provides:

> (c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.

470. MERC requested that the salaries of the sixth through tenth highest paid employees be kept nonpublic for competitive reasons related to the compensation of MERC's employees because publicly disclosing this information could give competitors an advantage in terms of hiring and retaining key employees and it would be inappropriate to ignore the employees' interest to keep this information private.[485]

471. The salaries of the sixth through tenth highest paid employees should be treated as private data as individuals, as contemplated by Minn. Stat. § 216B.16, subd. 17(c).

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minnesota Statutes Ch. 216B and Minn. Stat § 14.50 (2010).

2. The parties received due an proper notice of the hearing and MERC has complied with all procedural requirements of statute and rule.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05.

[485] Ex. 41 at 58 (S. DeMerritt Direct).

4. The burden of proof to show that a rate change is just and reasonable shall be upon the public utility seeking the change.[486] Any doubt as to reasonableness should be resolved in favor of the consumer.[487]

5. MERC has shown that the issues that have been resolved by the parties result in rates that are in the public interest and those issues should be approved by the Commission.

6. Modifying MERC's natural gas rates in the manner described in the Findings and Conclusions above results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

7. The rate finally ordered by the Commission should be compared to the interim rate set in the Commission's January 28, 2011 Order Setting Interim Rates, and a refund should be ordered to the extent that the interim rate exceeds the final rate, subject to any true-up ordered regarding any particular expense.

8. Any of the Findings more properly designated Conclusions are hereby adopted as such.

RECOMMENDATION

Based on the foregoing Findings and Conclusions, IT IS RECOMMENDED that the Minnesota Public Utilities Commission orders that:

1. MERC is entitled to increase gross annual revenues in the manner and in an amount consistent with the terms of this Order.

2. Within ten days of the service date of this Order, MERC shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning with the effective date of the new rates, and the rate design decisions contained herein. MERC shall include proposed customer notices explaining the final rates. Parties shall have 14 days to comment.

3. If the Commission orders an Interim Rate Refund within 30 days of the service date of this Order, MERC shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein. Parties shall have 14 days to comment.

4. The concepts set forth in these Findings and Conclusions should govern the mathematical and computational aspects of the Findings and Conclusions. Any

[486] Minn. Stat. § 216B.16, subd. 4.
[487] Minn. Stat. § 216B.03.

computations found to be in conflict with the concepts expressed should be adjusted to conform to the concepts expressed in the body of this Report.

Dated: _April 2, 2012______________

__/s/ Manuel J. Cervantes____________
MANUEL J. CERVANTES
Administrative Law Judge

Reported: Transcript Prepared (three volumes)
Shaddix & Associates

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, any party adversely affected by this Report may file exceptions to it within 15 days of the mailing date hereof. Exceptions should be filed with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 Seventh Place East, St. Paul, MN 55101. Exceptions must be specific and stated and numbered separately and should include Proposed Findings of Fact, Conclusions and an Order. Exceptions should be e-filed with the Commission and served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply. An original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions or after oral argument, if held. Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 216B.16, subd. 1a, if the Commission rejects or modifies the settlement agreements reached herein, this matter may be extended by 60 days for conclusions of the proceeding.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

OAH 16-2500-21807-2
MPUC Docket No. G-007,011/GR-10-977

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
Minnesota Energy Resources Corporation
for Authority to Increase Rates for Natural
Gas Service in Minnesota

ATTACHMENT A:
SUMMARY OF PUBLIC COMMENT

Pursuant to Minnesota Rule 7829.1100, the Administrative Law Judge conducted public hearings to elicit public comment regarding MERC's requested rate increase.

Public hearings were held at the Olmsted County Government Center in Rochester, Minnesota and the Dakota County Technical College in Rosemount, Minnesota on June 23, 2011.

At the public hearing in Rochester, MERC was represented by Greg Walters, MERC's Regulatory and Legislative Manager, and David Kult, MERC's General Manager of Operations and Engineering. In addition, Stan Shreve, MERC's Operations Manager for the Southeast Minnesota region, attended the hearing. Vincent Chavez, an analyst with the OAG, attended the public hearing on behalf of OAG.

At the public hearing in Rosemount, MERC was represented by Greg Walters and David Kult. Dr. Marion Griffing, a financial analyst with the Department, Ray Smith, a financial analyst with the OAG, and Robert Harding, a rates analyst with the Commission also attended the hearing.

No members of the public attended the hearings in Rochester or Rosemount.

An additional public hearing was held at the City Hall in Cloquet on June 27, 2011. Seven members of the public attended this hearing.

At the public hearing in Cloquet, MERC was represented by Greg Walters, David Kult, David Valine, MERC's Northwest Regional Manager, and Ken Bergstedt, MERC's Northeast Regional Manager. Mark Johnson, a financial analyst with the Department, and Tracy Smetana, Commission staff, also attended the hearing.

At the outset of the public hearing in Cloquet, the Administrative Law Judge made introductory remarks, followed by short remarks from Greg Walters and Mark Johnson. Following these remarks, three members of the public spoke. A summary of their comments follows below:

SUMMARY OF PUBLIC HEARING COMMENT

1. Robert Bassing, a ratepayer from Buhl, Minnesota, commented that MERC should actively solicit customers to convert from fuel oil to gas to widen its customer base as a means of raising revenue and increasing profit. Mr. Bassing stated that to have a rate increase due to maintenance or salary costs is acceptable, but for MERC to fail to expand its residential customer base reflects inefficient management and should not be a reason to increase rates. Mr. Bassing also expressed concern about MERC's proposed decoupling mechanism and worried that it would allow MERC to raise rates in the future without Commission approval. Mr. Bassing stated that it does not make sense for MERC to argue that it wants to decouple from regulation but that it still expects to be able to raise rates in the event of lower sales revenues.[488]

2. Carol Strom, a ratepayer from Cloquet, expressed concern over the ability of the elderly and retirees on fixed incomes to afford increased gas rates. Ms. Strom pointed out that she and other retirees have not seen a raise in their Social Security income in three years, and she suggested that MERC find ways to reduce costs associated with upper management staffing and benefits before requesting an increase in gas rates.[489]

3. Susan Pedersen, a ratepayer from Moose Lake, raised questions about the accuracy of her meter and gas bills.[490]

4. In addition to the testimony taken at public hearings, about 22 ratepayers submitted written comments to the Administrative Law Judge before the close of the comment period on July 7, 2011. A summary of most of the written comments follows below:

SUMMARY OF WRITTEN PUBLIC COMMENTS

5. *Margaret Reiner*, a ratepayer, opposed the requested rate increase given the current economy. Ms. Reiner stated that small businesses are struggling to survive and cannot afford any more rate increases. Ms. Reiner noted that small companies have to compete against many big companies, yet energy companies have very little competition. Given this lack of competition, Ms. Reiner asserted that MERC and other energy companies should not be allowed to keep increasing rates.

D. Anderson, a ratepayer from Eagan, opposed the requested rate increase given the state of the economy. Ms. Anderson noted that many people are out of work

[488] Cloquet Public Hearing Transcript at 14-18.
[489] Cloquet Public Hearing Transcript at 21-22.
[490] Cloquet Public Hearing Transcript at 23-42 and Public Exhibit 2.

or have taken jobs at greatly reduced salaries and cannot afford a rate increase. Ms. Anderson stated that now is not the time to be raising rates and asserted that "the greed has to stop." Ms. Anderson also questioned why rates need to be raised when she frequently hears reports on how plentiful and much cheaper natural gas is compared to other sources of energy.

6. *Joyce Nordquist*, a ratepayer from Jackson, expressed concern that the elderly living on fixed incomes and many low income families will be overly burdened by a rate increase. Ms. Nordquist requested that MERC make cuts in spending rather than increase its gas rates.

7. *Mitch and Robin Klebig*, ratepayers from Rochester, strongly disagreed with the proposed gas rate increase. The Klebigs maintain that there is no justification for raising gas rates when natural gas prices in the commodities market are at or near multi-year lows. The Klebigs argue that a gas rate increase amounts to another tax on Minnesota citizens at a time when many people are without jobs or facing job losses in the near future. According to the Klebigs, allowing such a non-market-based rate increase now will set a precedent for rates to be raised dramatically when natural gas prices actually rise in the commodities market. Instead of raising gas rates, the Klebigs suggest that MERC look for inefficiencies and ways to streamline processes in order to cut costs and create savings.

8. *Tim Blanchard*, a ratepayer from Grand Rapids, opposed the requested rate increase. Mr. Blanchard asserted that MERC's need to increase rates is unfounded given that wholesale gas prices are hovering around $4.30/MCF and MERC is currently charging $9.77/MCF. Mr. Blanchard contended that MERC's 227% increase over wholesale prices represents an exorbitant fee for delivery of services.

9. *Darlene Mainella*, a ratepayer from Cloquet, objected to the requested rate increase when utility companies make huge profits and people living on Social Security have not seen a cost of living increase.

10. *David Ernest*, a ratepayer from Mora, opposed the requested rate increase and recommended that the rate structure be shifted so that the residential and transportation customer classes receive a lower percentage of the proposed rate increase and commercial classes receive a higher percentage of the proposed rate increase. Mr. Ernest expressed the opinion that the rates commercial classes pay are being subsidized by "the excessive rates residential customers are currently paying." Mr. Ernest maintained that residential users are the backbone of the state and their interests should be placed above corporate profits. Mr. Ernest argued that "basic justice" requires a uniform and just pricing structure that ensures all citizens and commercial interests pay their fair share based on the therms used. Finally, Mr. Ernest opposed MERC's proposed decoupling mechanism, which would allow MERC to adjust only the rates paid by residential and small commercial customers based on shortfalls or excesses in projected sales. According to Mr. Ernest, if decoupling is a valid mechanism it should apply to all rate-paying classes.

11. *Don and Laurel Donahue*, ratepayers from Duluth, opposed the requested rate increase. The Donahues stated that they are both retired and trying to cover the ever- increasing costs of food, gas, and prescription medications on modest fixed incomes. The Donahues assert that MERC does not need a rate increase at this time and should instead tighten its belt like its ratepayers are doing to get by in this difficult economic time.

12. *Robert Anderson*, a ratepayer from Rosemount, opposed the requested rate increase. Like the Donahues, Mr. Anderson stated that he is retired and can ill afford a rate increase. Mr. Anderson noted that MERC is the only supplier of natural gas in his area and that he cannot shop around for another source with a better price. Mr. Anderson maintained that a gas rate increase should not be considered until the economy stabilizes.

13. *Robert Langen*, a ratepayer from La Crescent, opposed the requested rate increase. Mr. Langen is retired and noted that he has not seen an increase in his retirement income in a number of years. Mr. Langen recommended that MERC initiate cost cutting measures within the company rather than passing new costs on to the ratepayers.

14. *Allen Ettesvold*, a ratepayer from Bemidji, opposed the requested rate increase. Mr. Ettesvold questioned why MERC needs to increase its profit by $13.7 million and what it intends to do with the money. Mr. Ettesvold wondered if MERC intends to acquire competing utilities or other businesses, pay out bonuses to top executives, or upgrade their systems. Mr. Ettesvold stated that he does not want to see gas rates increased so that MERC may buy up competition to expand its monopolistic situation. Mr. Ettesvold also opposes MERC's request to decouple its revenue, which would permit MERC to adjust its rates higher in the event projected sales revenue decreases due to, for example, ratepayers' conservation efforts. According to Mr. Ettesvold, MERC's proposed decoupling mechanism does not have the public's interest in mind.

15. *Kathleen Vondracek*, a rate payer from Tracy and the Principal of St. Mary's Elementary School, raised concerns regarding MERC's requirement that Saint Mary's School purchase telemetry equipment at a cost of $1,200-$2,000 and provide a dedicated telephone line in order for MERC to read its meters and produce billings. Ms. Vondracek opposed MERC's telemetry equipment purchase requirement.

16. *Janet Lasch*, a ratepayer from North Branch, opposed MERC's requested rate increase. Ms. Lasch stated that, in the current economy, every business, government agency, middle income, and retired person has to cut their budgets to the bone. Given this, Ms. Lasch believes that even a modest increase in residential rates will mean the difference between being able to purchase the basics or go without.

17. *Arthur Arnold*, a ratepayer from Duluth, opposed MERC's requested rate increase. In particular, Mr. Arnold objects to MERC's position that MERC should be permitted to raise its rates to make up for reduced sales of natural gas. According to

Mr. Arnold, a public utility should not expect to always maintain or increase its profits and it should not be permitted to charge customers more to make up a shortfall in sales revenues. Mr. Arnold also contended that MERC has not demonstrated any increase in operating costs and he opposed merging MERC's PNG and NMU rate areas as that will raise PNG's rates.

18. *Mark Anderson*, a ratepayer from Moose Lake, opposed MERC's requested rate increase. Given the current economy with many people out of work and the rising cost of food and health insurance, Mr. Anderson urged the Commission not to permit MERC to increase gas rates.

19. *Bob Koester*, a ratepayer in southern Minnesota, opposes MERC's requested rate increase. Mr. Koester questioned why MERC needs another rate increase, especially a 5.9% increase, when media reports indicate there is an abundance of natural gas. Mr. Koester also expressed skepticism about MERC's proposed decoupling mechanism for residential and small commercial customers. Mr. Koester believe that it is highly unlikely MERC would ever adjust its rates down. He also argues that MERC should not be allowed to raise its rates to make up for lower sales due to energy conservation.

20. *Jack Johnson*, a ratepayer from Eveleth, opposes MERC's requested rate increase. Mr. Johnson maintained that there is no basis for an increase in rates when natural gas supplies are at an all-time high and costs for gas should be going down.

21. *Robert Langen*, a ratepayer from La Crescent, opposed MERC's requested rate increase. Mr. Langen stated that MERC should initiate cost cutting measures within its own company and not pass new costs on to its customers. Mr. Langen noted that as a retired person, he has not seen an increase in his Social Security for a number of years and he has cut back plenty.

22. *Morgan St. Main*, a Minnesota ratepayer, opposes MERC's requested rate increase. Mr. St. Main argues that the Commission should not "bail out" MERC and permit inefficiencies to be built into the retail price of natural gas. Mr. St. Main also objected to MERC's revenue decoupling mechanism, arguing that it is a means for MERC to opt out of the market and demand a subsidy when sales revenues decrease.

23. *James Licari*, a ratepayer from Rochester, opposed MERC's requested rate increase. Mr. Licari maintains that increasing the per therm rate for residential customers from .17746 to .21748 is out of line, especially when the supply of natural gas is robust and its one of the few energy resources the U.S. owns. Mr. Licari also said that MERC should restructure its business to account for lower demand and not just pass higher rates onto customers.

24. *Lane Wagoner*, a ratepayer from Rochester, opposed MERC's requested rate increase. In particular, Mr. Wagoner objected to MERC justifying its proposed rate increase (in part) on reduced sales caused by customers' conservation efforts. Mr. Wagoner notes that the public is told over and over again to conserve energy by dialing

down the thermostat, installing insulation, and caulking cracks. These efforts should result in savings for energy customers. Yet, if a utility company is allowed to raise its rates based on reduced sales, consumers will not benefit from their conservation efforts. According to Mr. Wagoner, MERC, like any business, should cut costs and adjust its business to the decline in sales, rather than pass higher rates on to the ratepayers.

25. *Thomas Northfield*, a Minnesota ratepayer, opposed MERC's requested rate increase. Mr. Northfield argued that MERC's proposal to increase rates only for residential and small commercial classes is unfair and benefits big business and the wealthy at the expense of the poor and middle class. Mr. Northfield also asserted that energy conservation efforts on the part of ratepayers should be rewarded, not punished with higher rates.

26. The Commission also received a couple of anonymous comments from ratepayers objecting to MERC's requested rate increase. Like the comments above, these individuals expressed opposition to any rate increase in the current economic environment and voiced concern on the ability of the elderly and others on fixed incomes to absorb a rate increase.

M.J.C.